The great energy trap

An evaluation of the economic viability of replacing coal with gas in large power plants in Bulgaria

CEE Bankwatch Network

Za Zemiata
Friends of the Earth Bulgaria

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Table of acronyms

Acronym	Full name/meaning
BEH	Bulgarian Energy Holding
CCGT	combined cycle gas turbine
CHP	combined heat and power (cogeneration)
DAM	day-ahead market
DH/DHC	district heating/district heating company
ESO	Electricity System Operator (Bulgaria's transmission system operator)
EU ETS	EU Emissions Trading System
HHV	higher heating value, also gross caloric value (GCV)
HPP	hydropower plant
IBEX	Independent Bulgarian Energy Exchange
LCOE	levelised cost of electricity, as defined in World Energy Outlook by the International Energy Agency (IEA)[1]
LHV	lower heating value, also net caloric value (NCV)
ME	Maritsa East (Maritsa Iztok)
MWe	megawatts of electric capacity
NEC	National Electricity Company (Bulgaria)
NPP	nuclear power plant
PP	power plant
PPA	power purchase agreement
PV	photovoltaic
RES	renewable energy sources
SRMC	short-run marginal cost
TPP	thermal power plant
TSO	transmission system operator
YTD	year to date

[1] International Energy Agency, World Energy Outlook 2023, *International Energy Agency*, October 2023.

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Executive summary

With the more ambitious emissions reduction targets and the increased emission prices in recent years, almost all EU Member States, including Bulgaria, plan to exit coal and set coal phase-out dates. Currently, however, Bulgaria has no strategy or financial plan in place for replacing the major contribution of coal-fired power plants, covering both baseload (in winter months) and short-term load regulation needs.

One of the proposed solutions, which could provide a full capacity substitution that meets all technical reliability, availability and manoeuvrability requirements, is to replace coal-fired power plants with gas-fired counterparts. Often referred to as 'coal-to-gas conversion', this solution comprises a range of technical options (examined below) and typically requires a substantial rebuild.

Two general approaches for replacing the primary fuel in the existing coal-fired power plants with gas are considered (see Annex 1 for details). The more direct approach is to re-engineer the existing combustion equipment so that it can burn gas. This involves a thorough reconstruction of the boiler and flue gas treatment, decommissioning of the fuel and ash handling auxiliaries, building gas supply transmission pipelines, etc. This approach aims to reduce investment costs and the duration of the works. On the other hand, it has a very limited potential for increasing the (relatively low) overall plant efficiency of coal-fired condensation power plants.

The alternative approach is to build more efficient gas-fired units on the sites of the existing coal-fired plant, substituting their production and utilising some of the existing infrastructure. Such plants will have much more competitive operating costs, but will typically require higher investments and longer construction times.

In Bulgaria, existing coal-fired power plants have issued numerous statements committing to transition to gas by utilising CCGT units. Incidentally, a medium-scale project based on gas engines is now under construction.

This study examines two projects aimed at replacing coal with gas: a 1000 MW_e CCGT at the Maritsa East complex and a 39 MW_e gas-engine installation at Bobov Dol TPP.

Our analysis shows that, from an economic point of view, both projects are unfeasible based on current market conditions. All financial indicators remain strictly negative when their sensitivity is tested against reasonable variations in the main input parameters: capital expenditure (CapEx), electricity sale price, gas price, CO_2 emissions price, availability capacity price, utilisation factor, electrical efficiency.

To achieve a positive net present value (NPV), the 1000 MW_e CCGT installation at Maritsa East under consideration would need EUR 1.3 billion in financial support until 2040. Together with the CapEx, that equals a financial burden of over EUR 2.1 billion on public finances.

Similarly, in order to attain a positive NPV, the 39 MW_e installation at Bobov Dol TPP under consideration would require ≈ EUR 68 million in capacity or other form of support, exceeding 200 per cent of the estimated project CapEx.

With no capacity availability payments or other form of support, in order to achieve an NPV > 0, the two installations would require sale electricity prices exceeding EUR 200/megawatt hour (MWh), which is at least 40 to 50 per cent above the top 20 per cent of the market price percentile.

In addition to being financial unfeasible, replacing coal with gas is associated with the following risks and disadvantages:

- It is an investment in an unnecessary step on the path to emissions reduction, which will hinder the achievement of the net-zero target.
- It would consume funds, which could alternatively be invested directly in non-fossil energy sources;
- It bears and reinforces all the risks, associated with gas lock-in (geopolitical risk, increased dependence on imported fossil fuel, energy price volatility, stranded infrastructure and production assets, maintained CO_2 emission quantities and costs, etc.);
- Direct gas conversion of existing coal capacities would require up to 150 per cent increase in the imported annual gas volumes. That would be a challenge by itself, but it would also lead to even higher dependence on energy imports and would influence the gas prices in the region.

Objectives of the study

The main objective of this study is to analyse the economic viability of replacing coal with gas in Bulgaria's power plants. The analysis focuses on the current situation in the power production sector in Bulgaria, particularly coal-fired and gas-fired power plants. It also takes into account the various cost components of electricity produced from gas, and the expected market prices for the period 2025 to 2040. Thus, this study can be used to inform decision makers about the potential costs, their sensitivity to input variables, regulatory factors, and overall investment feasibility. We also discuss the probability and risks of medium- and long-term gas lock-ins in Bulgaria.

The scope of the study is confined to the electricity production sector. DH plants are not considered due to their relatively small share, social role, and the complexity of the related price regulations.

Overview of the power production context in Bulgaria

Production capacities

According to data from the ESO,[2] for the calendar year 2022 the installed electricity production capacities in Bulgaria were 13,505 GW, distributed by fuel base and plant type as follows:

Type	$MW_{installed}$
Nuclear (Kozloduy)	2 000
Lignite TPP	4 119
Black-coal TPP	356
Gas TPP	1 307
Hydropower	3 214
Wind	705
Solar PV	1 726
Biomass	77
Total	**13 505**

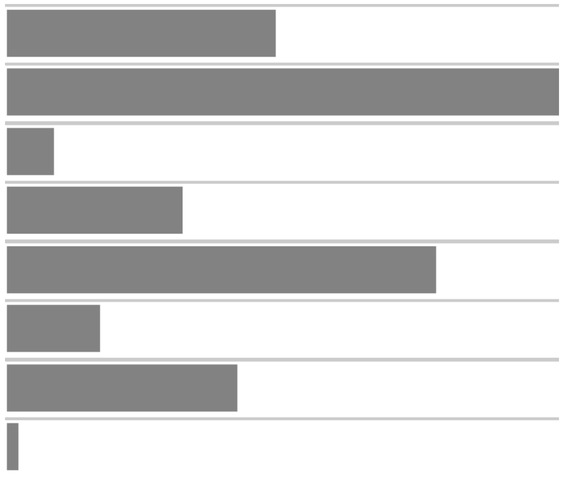


Table 1. Installed electricity production capacities in Bulgaria by type for 2022.[3]

In the last decade, the above capacities have remained relatively constant. The only recent significant change has been PV capacities, with a number of large PV plants built between 2021 and 2023. The connected PV capacity is expected to exceed 3000 MW_p by the end of 2023 and 5000 MW_p by the end of 2024.[4]

Production volumes

Electricity production volumes increased sharply in 2021 and even more in 2022 due to the increased electricity prices and thus the regained competitiveness of some coal/lignite power plants. As it can be observed in Table 2, this increased production was covered by the thermal power plants and was to a great extent related to export volumes, which more than tripled in 2022 compared to 2020. At the same time the gross domestic consumption in Bulgaria remained comparatively stable.

[2] ESO EAD, Statistical Pocketbooks, *ESO EAD,* 2022.

[3] Ibid.

[4] ESO EAD, '2023-2032 Plan for Development of Bulgaria's Transmission Electricity Grid', *ESO EAD,* 2023.

Production [GWh]	2020	2021	2022
Nuclear (Kozloduy)	16 630	16 489	16 465
Coal TPPs	15 052	20 169	23 825
Gas TPPs	2 500	2 788	2 638
Hydropower	3 393	5 127	3 811
Wind	1 478	1 434	1 499
Solar PV	1 478	1 488	2 023
Biomass	350	331	318
Total production	**40 881**	**47 826**	**50 579**
Export	-3 438	-8 819	-12 244
Gross consumption	37 443	39 007	38 335

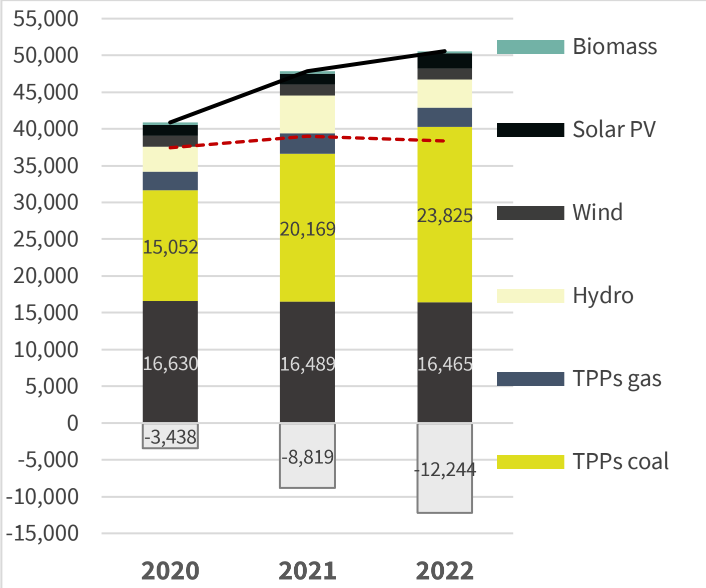
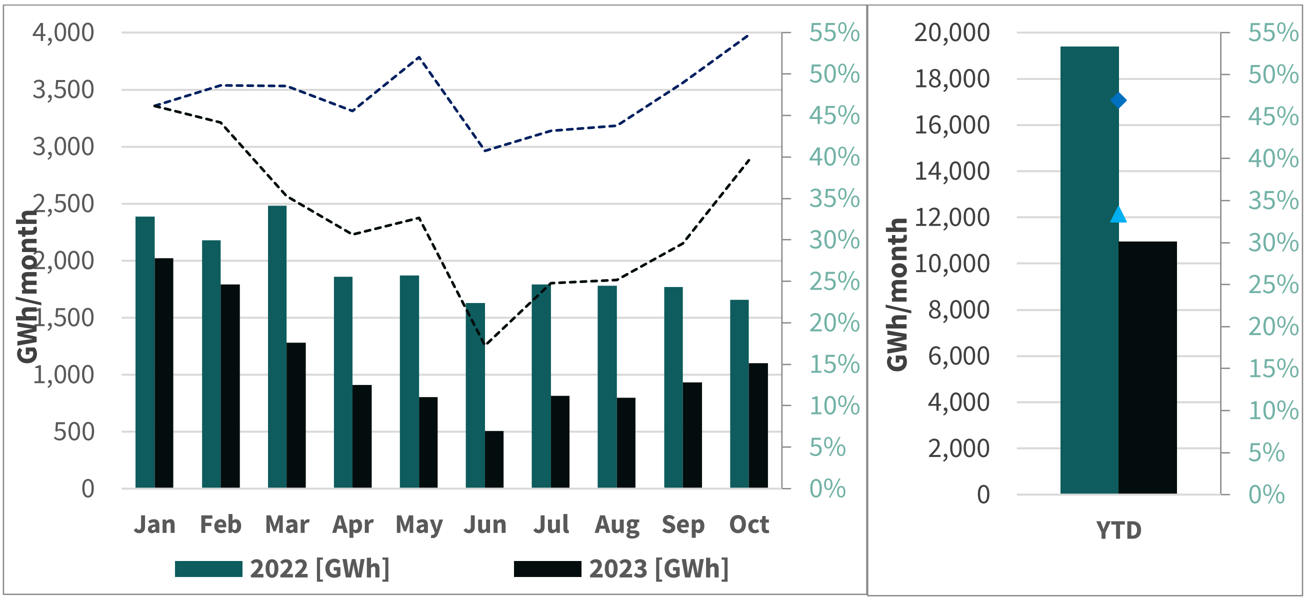


Table 2 *Figure 1*

Annual power production/export/consumption of Bulgaria - by plant type (GWh).[5]

In the first 10 months of 2023, due to the stabilisation of lower energy prices and high emissions prices, lignite TPPs failed to compete on the free market. As shown in Figure 2, production dropped by 43 per cent to levels approaching those recorded in 2020. Correspondingly, exports have dropped by 70 per cent.[6]



a) Monthly *b) Year-to-date (Jan-Oct)*

Figure 2. Comparison between 2022 and 2023 of electricity production (GWh) by coal power plants and their respective share as a percentage of total production in Bulgaria.[7]

[5] ESO EAD, Statistical Pocketbooks.

[6] ESO EAD, Energy Balance operational data, *ESO EAD,* 2024.

[7] ENTSO-E, Transparency Platform, *ENTSO-E,* 2023.

Another notable 2023-versus-2022 variation is the considerable 60 per cent increase in PV electricity overall.[8]

Electricity system loads

In 2022, the system load, excluding exports, fluctuated between an absolute minimum value of around 2800 MW and an absolute maximum of 7150 MW. The daily load variation, which is the daily maximum minus the daily minimum, typically fell within a range of 1000÷2000 MW, with extremes of a 780 MW minimum and a 2260 MW maximum.

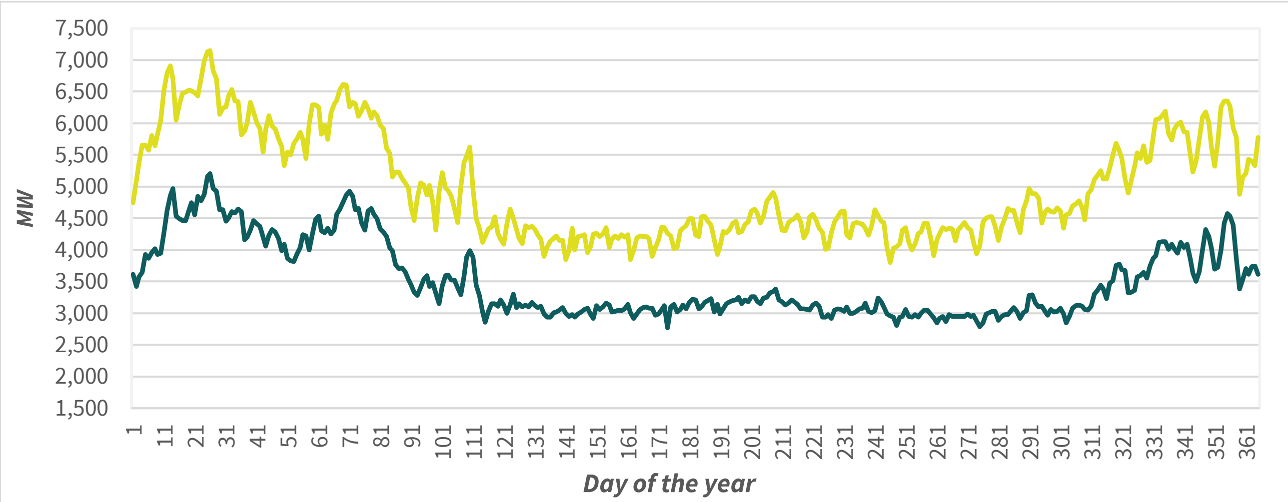


Figure 3. Daily minimum and maximum gross system loads for 2022.[9]

Since the maximum annual loads pertain to heating, they occur on days with the lowest outdoor air temperatures.

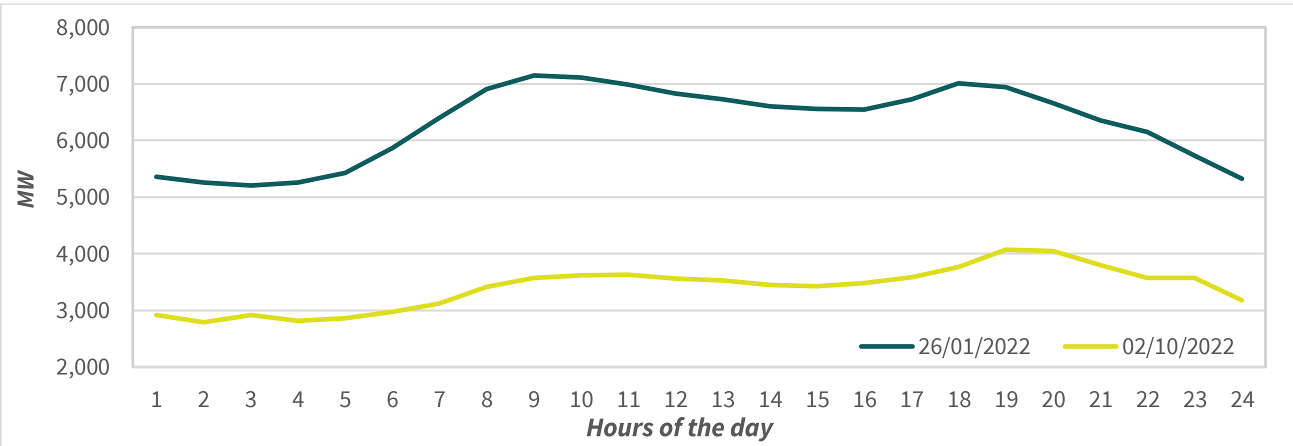


Figure 4. Hourly load profiles for absolute maximum and absolute minimum loads on specific days in 2022.[10]

[8] ESO EAD, Energy Balance operational data, *ESO EAD*, 2024.

[9] ENTSO-E, ENTSO-E Transparency Platform, *ENTSO-E*, accessed 5 March 2024.

[10] Ibid.

As shown in Figure 5, in 2022 loads above 5000 MW were present for < 2000 h, loads above 5500 MW – for ≈ 1000 h, and above 6500 MW – for ≈ 70 h. In 2020, 2021 the absolute maximums were < 7000 MW.

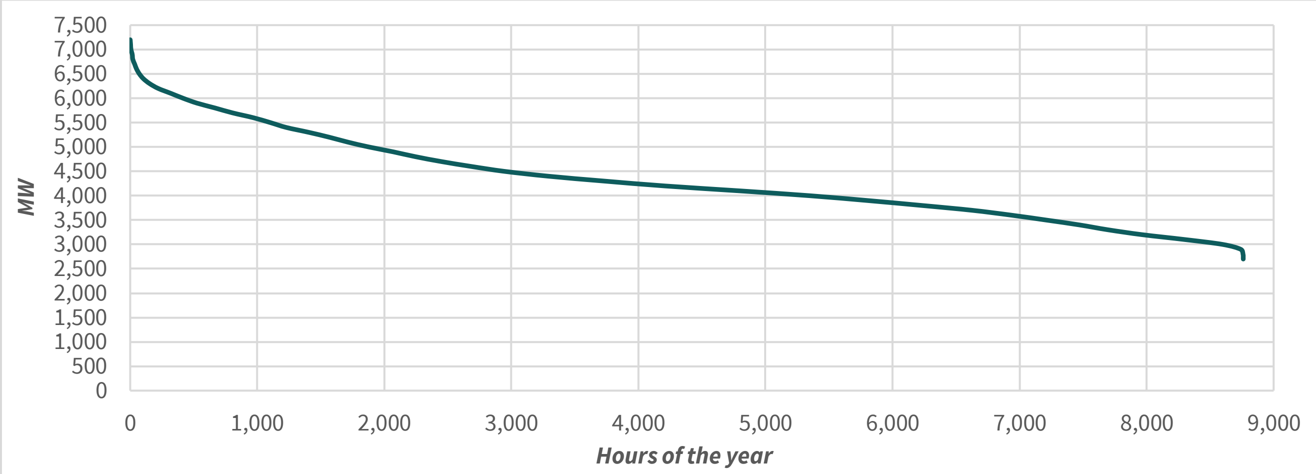


Figure 5. Duration curve of gross hourly system loads in 2022, excluding exports.[11]

Roles of the different types of production plants/sources, seasonality and regulation

The annual quantities of produced electricity for the last six years and the respective breakdown by plant type are illustrated in Figure 6.

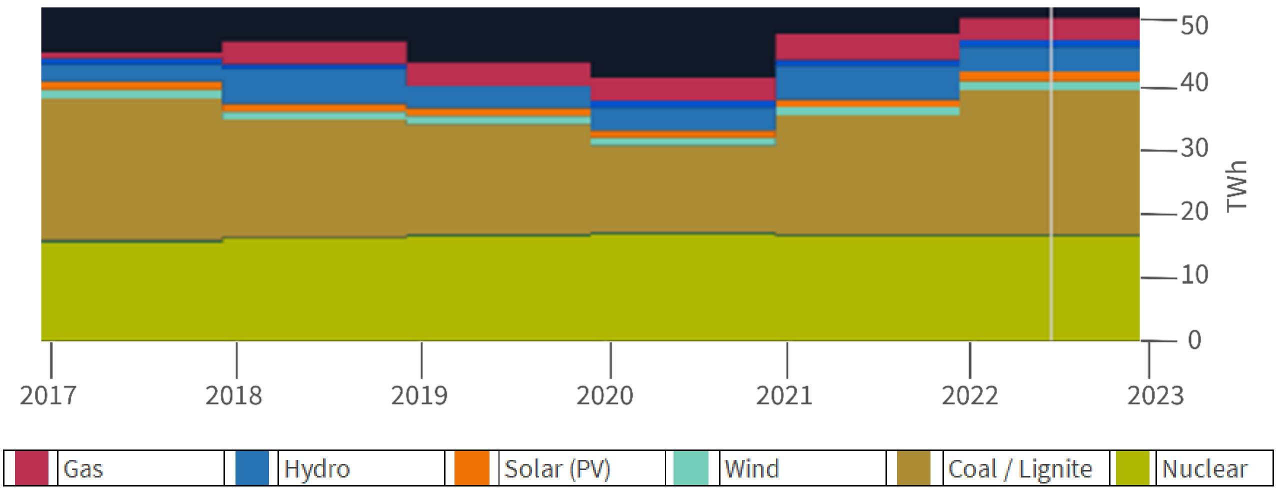


Figure 6. Annual electricity production quantities by production source type in terawatt hours (TWh) between 2017 and 2022.[12]

[11] Ibid.

[12] Electricity Maps, Electricity Map – Bulgaria, *Electricity Maps*, 2024.

The 2 blocks of the 'Kozloduy' NPP (up to 1.08 GW each) are used as base capacity, normally producing roughly 16 to 17 terawatt hours (TWh) per year, equivalent to between 30 per cent (in winter months) and 50 per cent (in summer months) of the total electricity output in Bulgaria.

PV, wind, some hydropower, and most high-efficiency CHP capacities are 'priority' producers. This means that their entire output is normally taken 'as is' into the system, with other needs regulated by other plants.

Therefore, on a seasonal and 24-hour basis, grid load regulation is provided (see Figure 7 and 8) mostly by:

- the large condensation coal/lignite power plants, as well as
- by pumped storage and some large hydropower plants, which frequently provide > 1.0 GW regulation capacity (even after the loss of the largest pumped storage capacity, Chaira, 0.8 GW, after being seriously damaged in 2022).[13]

The contribution of thermal power plants is considerable and cannot be avoided when faced with high system loads, such as during winter when output is limited. Their role has become more important for load manoeuvring since the Chaira breakdown.

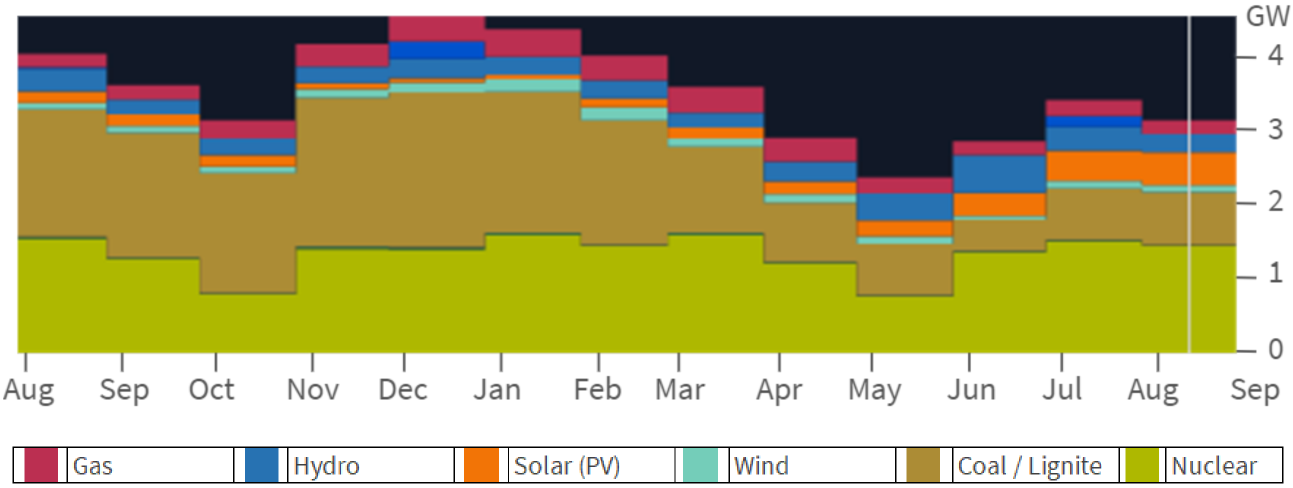


Figure 7. Monthly electricity production quantities (in TWh) by production source type between August 2022 and August 2023.[14]

As shown in Figure 6, the total output of large condensation coal and lignite power plants, including the share of total production, decreased steadily until the end of 2020. However, due to increases in gas and power prices in 2021 and especially in 2022, their production and share increased by more than 30 per cent

[13] The works required and the respective schedule for repairing PSHPP Chaira's equipment are still under assessment. According to statements by of NEC's CEO and the Minister of Energy in November 2023, two of the units should be back in operation in 2025, the third in 2026, and the fourth possibly in 2027 (Vladislava Peeva, Renovation of the Chaira PSHPP starts next year with the aim to be partially operational in 2025, *Mediapool.bg*, 30 November 2023).

[14] Electricity Maps, Electricity Map – Bulgaria, *Electricity Maps*, 2024.

and 60 per cent, respectively, compared to 2020. With the normalisation of energy prices in 2023, the share decreased steadily before increasing slightly after 1 July 2023.[15]

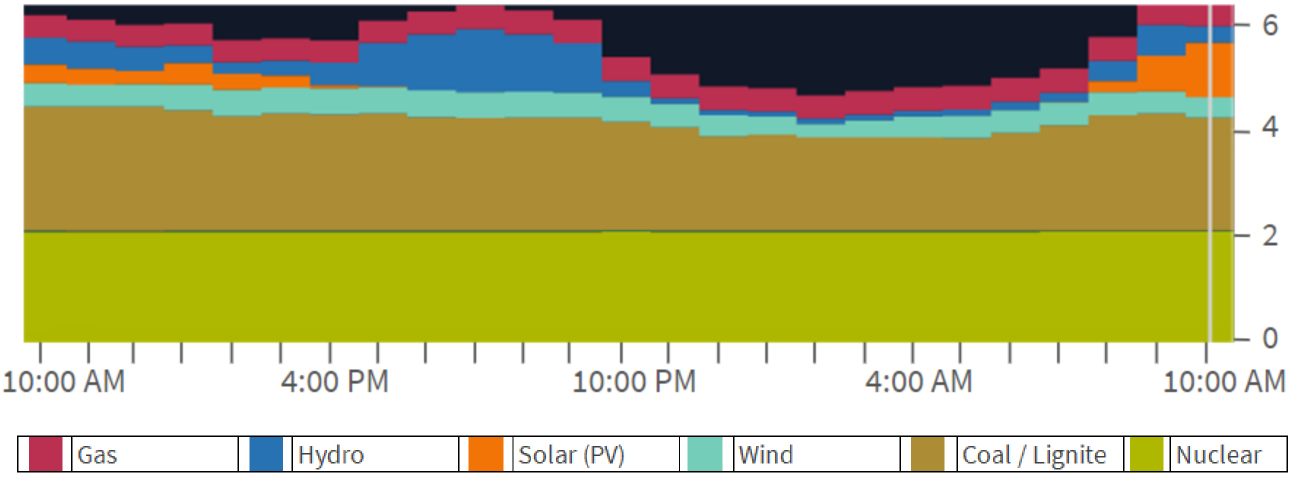


Figure 8. Daily electricity production power (in GW) by source type on working days in November 2023.[16]

The above figures demonstrate that the annual contribution of gas-fired plants was moderate (≈ 6 per cent). Since they are mostly DH plants, this is even lower in summer months (≈ 4 per cent).

In 2023, Varna TPP had the biggest gas-fired electricity production capacity with 630 MW_e (three blocks of 210 MW_e each). However, it has been operating for limited intervals in recent years (after its reconstruction to gas-fired Its maximum utilisation (≈ 13 per cent; 0.7 TWh produced) was in 2021, when gas prices in Bulgaria were as low as EUR 15/MWh, and the clean spark spread[17] was significant. In 2022, following the increase in gas prices, only one block was operating at an average load below 100 MW during January.

Toplofikacia Sofia (DH) has 277 MW_e installed in gas-fired CHP units. Together with six or seven smaller gas-fired DH plants, it is one of the above 'priority' producers. Their electricity output follows the heat production, so practically they are not used for system balancing/regulation.

Electricity price levels in 2023 (non-regulated market)

Electricity prices in Europe stabilised after the surge in the end of 2021 and the whole 2022. In Bulgaria in particular, after March 2023 the monthly averages fell below EUR 100/MWh (see Figure 9).

[15] Maritsa East 2 TPP was included in the regulated market mix with 2 200 GWh, by an Order of the Minister of Energy, aiming to avoid the loss of coal-fired capacities, needed to guarantee the security of the national electricity system.

[16] Electricity Maps, [Electricity Map – Bulgaria](#).

[17] 'Clean spark spread' is the wholesale market price of electricity minus the cost of fossil gas and the respective emission allowances necessary to produce it.

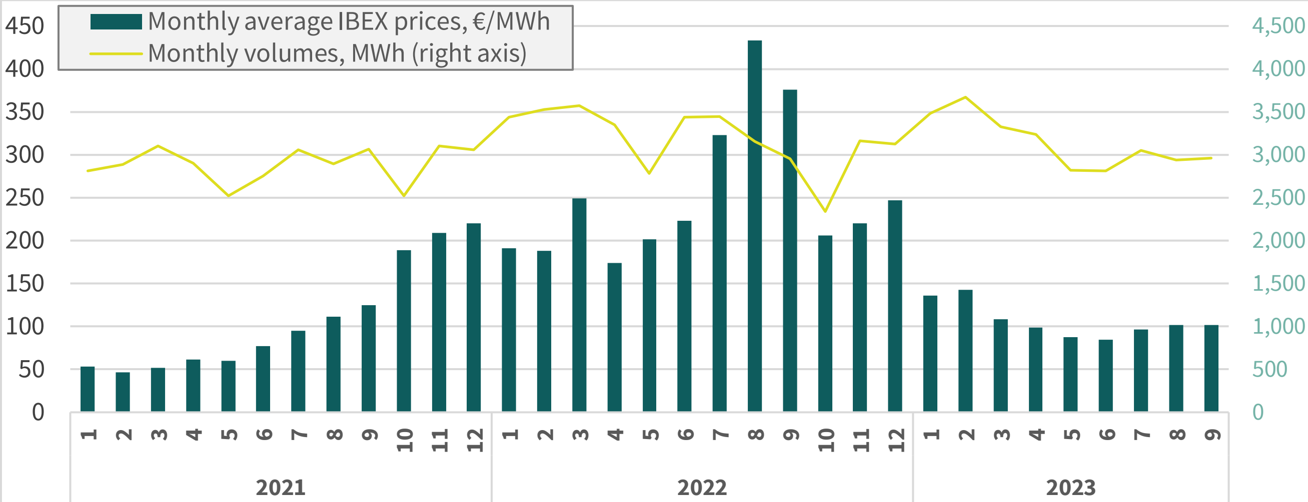


Figure 9. 2021÷2023 monthly average IBEX day-ahead market prices [EUR/MWh] and volumes [MWh/h].[18]

Reviewing the hourly prices in 2023 (Figure 10), the 10-day average varied within a range of EUR 70 ÷ 160/MWh, but the dispersion around the average values was quite significant.

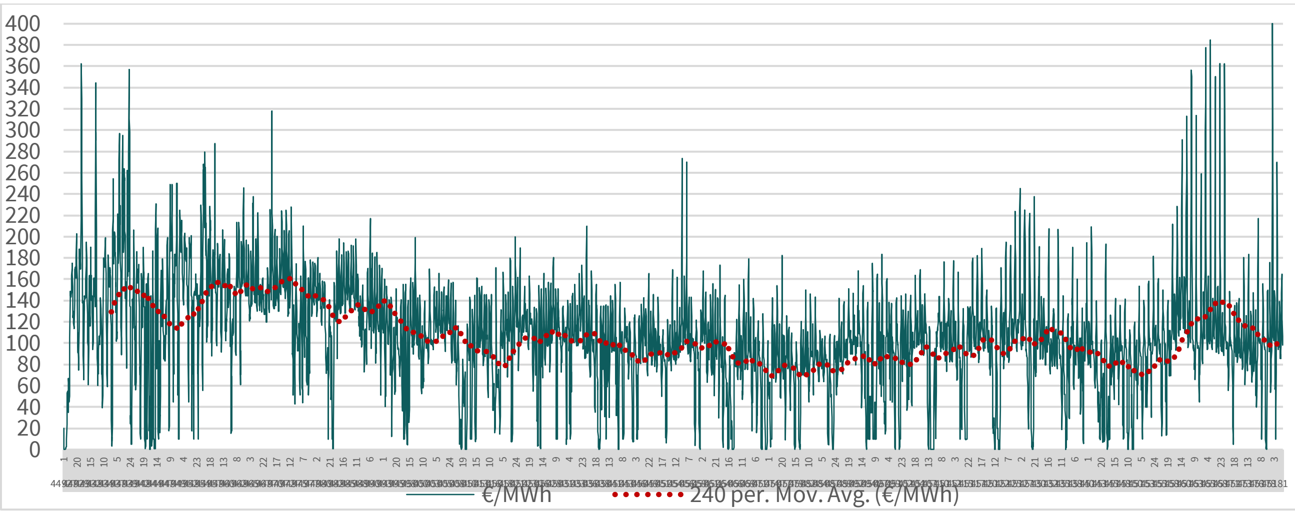


Figure 10. Hourly and 10-day moving average price [EUR/MWh] based on the IBEX day-ahead market between January and September 2023.[19]

As illustrated in Figure 11, more detailed analysis reveals that from 1 January 2023 to 1 October 2023 the IBEX DAM price fell:

- below EUR 100/MWh ≈ 43 per cent of the time
- below EUR 150/MWh ≈ 83 per cent of the time
- below EUR 180/MWh ≈ 93 per cent of the time
- below EUR 200/MWh ≈ 97 per cent of the time

[18] Independent Bulgarian Energy Exchange (IBEX), IBEX, *Independent Bulgarian Energy Exchange,* 2024.

[19] Ibid.

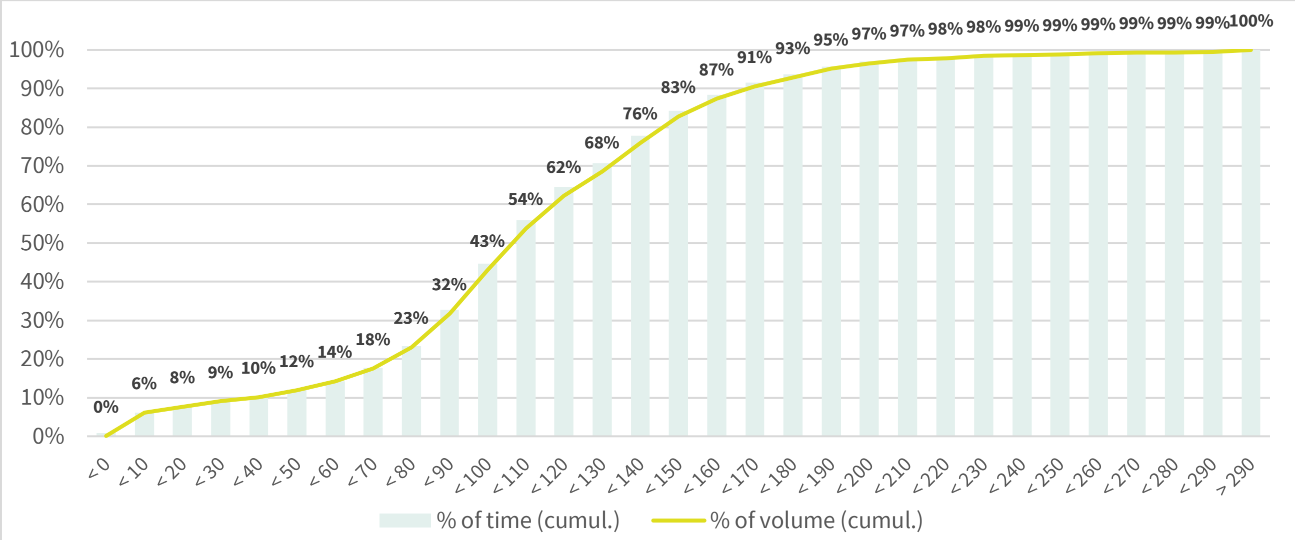


Figure 11. Cumulative duration percentage of IBEX electricity prices [EUR/MWh] falling below the given value between January and September 2023.[20]

A similar pattern can be shown for the deficit balancing electricity prices given by the TSO, which, between 1 January 2023 and 1 October 2023 was:

- below EUR 100/MWh ≈ 46 per cent of the time
- below EUR 150/MWh ≈ 73 per cent of the time
- below EUR 180/MWh ≈ 88 per cent of the time
- below EUR 200/MWh ≈ 93 per cent of the time

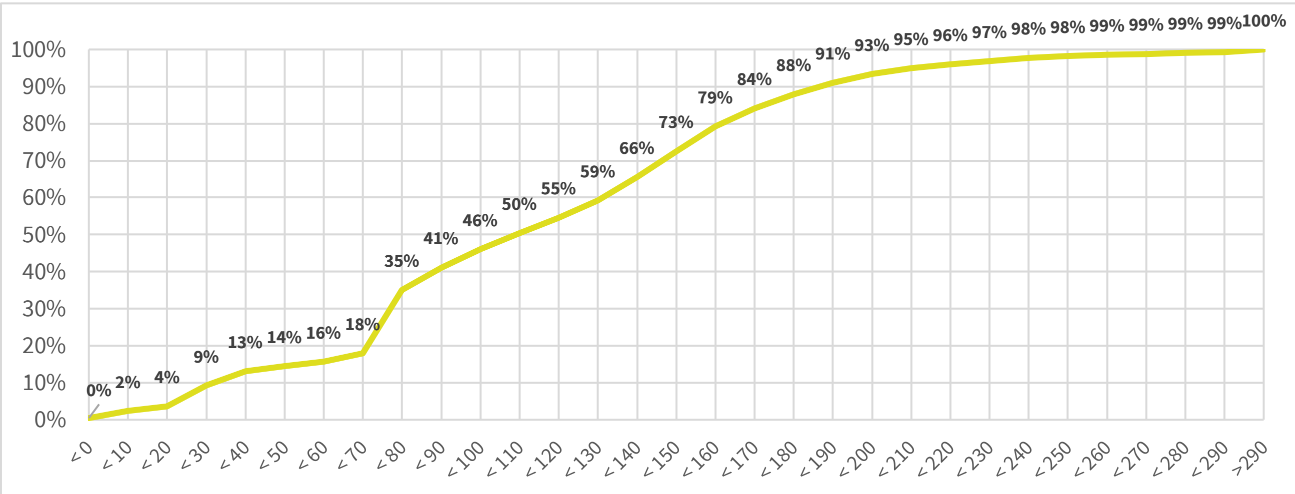


Figure 12. Cumulative duration percentage of the deficit electricity price [EUR/MWh] falling below the given value between January and September 2023.[21]

[20] Ibid.

[21] ESO EAD, Balancing Energy, *ESO EAD*, 2023.

It should be noted that the 2023 data in the last three charts does not include October, November and December, so the non-heating season is with a higher weight and therefore the analysis might yield lower prices than if a full calendar year were considered. It can, however, be argued that the prices in the first 2-3 months of 2023 were still rather high and they may compensate the above incomplete data.

Climate targets and commitments of Bulgaria

Bulgaria's commitments related to emissions reduction and other climate-related targets have been changed several times in the last 2 years, and are in constant dynamics in recent weeks (with ongoing protests of miners and TPP workers from coal regions).

At the time of writing the present study (September to November 2023), it is not clear whether the commitment of the national recovery and resilience plan to a 40 per cent reduction in CO_2 emissions in the power sector by 2026 (compared to 2019 levels) will be confirmed or renegotiated. It is similarly uncertain whether a deadline for ceasing electricity production from coal will be set; before October 2023, the years 2030 and 2038 had been discussed.

It is very likely that all Bulgaria's strategic documents on the transition of energy production, climate, decarbonisation and emissions will be revised in the following months, according to the most recent Climate Neutrality Roadmap of Bulgaria.[22]

General comments on coal power plants perspectives

- No plan or strategy has been developed by Bulgarian institutions on how sufficient grid regulation/balancing capacity (which is presently provided to a great extent by lignite- and coal-fired condensation power plants) shall be ensured in the short and medium term.
- According to EU Regulation 2019/943,[23] all power plants with specific CO_2 emissions above 550 g per kilowatt hour (kWh) will not be able to receive state support after 2025, a ruling that effectively applies all coal plants in Bulgaria. This includes payments and commitments for future payments under the capacity mechanism.
- In its 2023/2024 price decision,[24] Bulgaria's Energy and Water Regulatory Commission (EWRC) refused to allocate availability capacity to Maritsa East 2 Bobov Dol, and two other coal-fired power plants. Referring to art. 21, para. 1, p. 21, sent. 2 of the Energy Act,[25] the EWRC stated that 'availability capacity shall not be allocated to producers, whose regulated price is >10 per cent

[22] Council of Ministers of the Republic of Bulgaria, 'Climate Neutrality Roadmap of the Republic of Bulgaria', *Council of Ministers of the Republic of Bulgaria,* 5 October 2023.

[23] European Parliament, Council of the European Union, REGULATION (EU) 2019/943 of 5 June 2019 on the internal market for electricity, *EUR-Lex,* 2019.

[24] Energy and Water Regulatory Commission (EWRC), Price decision № Ц-14/30.06.2023, *EWRC,* 2023.

[25] The Energy Act valid as of the date of this decision (30 June 2023), i.e. the version amended in State Gazette, issue 11 of 2 February 2023, Ministry of Environment, Energy Act, February 2023.

above the forecast market price for the regulated period'. For 2023 and 2024, the forecast market price is ≈ EUR 131/MWh. Different coal TPPs exceeded it by 24 to 83 per cent.

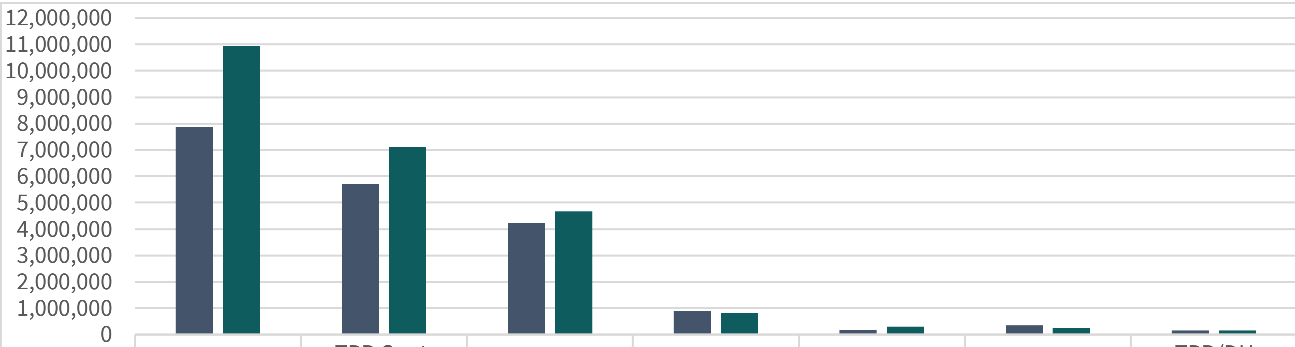
- Despite the abovementioned regulations and the uncompetitive electricity price, as of October 2023 it seems likely that the government will be forced to establish a mechanism to support the availability of the state-owned Maritsa East 2 plant and to use at least some of its capacity, especially during the winter months. It is unclear how long the state would be able to sustain the related additional costs and to what extent.

- Apart from that, it seems probable that other, or even all, coal power plants will be left to the market to determine their future. Since carbon capture and hydrogen will not be economically competitive in the next decade, some of them may try to adapt by replacing coal with gas or partially with biomass, while others shall probably have to stop operation.

Overview of the large coal-fired power plants in Bulgaria

Categorisation of the plants by capacity, coal type and fuel energy cost (lignite or not)

The officially declared and verified CO_2 emission quantities of the seven largest coal-fired emitters in the Bulgarian energy sector are given in Figure 13.



	TPP ME_2 (lignite)	TPP Cont. Global-ME_3 (lignite)	TPP AES ME 1 (lignite)	TPP Bobov Dol (coal)	TPP/DH Ruse East (coal)	TPP Brikel (lignite)	TPP/DH Republika Pernik (coal)
2019	7,874,098	5,703,965	4,234,815	875,384	182,341	351,248	143,561
2022	10,926,444	7,131,567	4,673,387	810,331	301,483	261,777	160,392

Figure 13. CO_2 emissions of large coal-fired power plants in 2019 and 2022 measured in metric tonnes of carbon dioxide (t_{CO2}).[26]

The officially reported EU ETS emission quantities for the last four plants in Figure 13 (Bobov Dol, Ruse East, Brikel, Republika) have been significantly reduced in recent years due to the declared use of large proportions of biomass in the fuel mix. It should be noted that the credibility of these declared biomass quantities is questioned by investigative journalists and non-governmental organisations including

[26] Executive Environment Agency, EEA, *Executive Environment Agency*, 2022.

Za Zemiata since 2021 and (for some of these plants) is under investigation by the European Public Prosecutor's Office.

For the purposes of the present study, the plants which are part of DH companies or systems (i.e. the thermal energy is also utilised) are to be excluded from the analyses. These are Republika and Ruse East, as well as Brikel (the latter is a CHP plant, where DH represents 1-2 per cent of the turnover).

Therefore, the following plants, representing more than 90 per cent of the annual CO_2 emissions in Bulgaria's energy sector, remain:

Large lignite power plants in the Maritsa East region

- **Maritsa East 2**

State-owned by Bulgarian Energy Holding, Maritsa East 2 is the largest TPP in Bulgaria with a capacity of 1620 MW.

- **Contour Global Maritsa East 3**

Installed capacity of 908 MW. The plant's PPA with NEC ends in Q1, 2024.

- **AES Maritsa East 1**

Installed capacity of 700 MW. The plant's PPA with NEC ends in 2026.

These three plants alone emitted 61 per cent of all CO_2 emissions from EU ETS stationary installations in Bulgaria in 2019 and 67 per cent in 2022.

The primary fuel in these plants is lignite, supplied by the state-owned company Maritsa East Mines EAD. They are all condensation plants, with annual average net electrical efficiencies between 27 per cent and 31 per cent and specific CO_2 emissions within a range of 1200 to 1350 g_{CO_2} per kWh net electricity (i.e. far above the 550 g_{CO_2}/kWh threshold noted in section 0).

They sell their electricity predominantly on the regulated market, according to quotas allocated by the EWRC.

Bobov Dol

This is a condensation coal-fired plant composed of 3 units with electric capacity of 210 MW each.

The plant was designed to use brown coal. 2021 and 2022 official reports state fuel base composed of:

- Biomass: 62 per cent of input fuel energy share
- Coal (mixture of brown and lignite): 37 per cent of input fuel energy share
- Heavy fuel oil: 1 per cent of input fuel energy share

The declared biomass quantities – 807,533 tonnes for 2022 and 891,424 tonnes in 2021 – are questionable. Based on these figures, however, verified emissions account for less than 3 per cent of all CO_2 emissions from EU ETS stationary installations in Bulgaria between 2019 and 2022.

In 2021 and 2022, the plant's net output was ≈ 1900 GWh or ≈ 4 per cent of national production.

The annual average net electric efficiency is around 28 per cent. According to the declared 2022 fuel mix, the specific CO_2 emissions are ≈ 520 g_{CO_2} per kWh net electricity, which was even lower in 2021. That falls below the 550 g_{CO_2}/kWh threshold noted in section 'Climate targets and commitments of Bulgaria' (page 15).

Analysis of current levels of specific fixed & variable electricity costs for typical plants

Maritsa East 2

The annual costs of the company are declared to and approved by the EWRC. For the regulation period 2023/2024 their levels are as given in Table 3. These costs do not include the rate of return (margin/profit), not the 5 per cent fee on electricity sales for the 'Security of the Electricity System' Fund.

	Cost category	kBGN	kBGN
Variable	Coal (lignite)	337 537	**2 339 746**
	Emissions allowances[27]	1 953 793	
	Consumables (limestone)	37 025	
	Water use	209	
	Electricity from free market	3 345	
	Ash deposition	7 837	
Fixed	salaries, insurances & social	138 000	**356 257**
	amortisations	138 944	
	Maintenance	35 910	
	Other fixed	43 403	

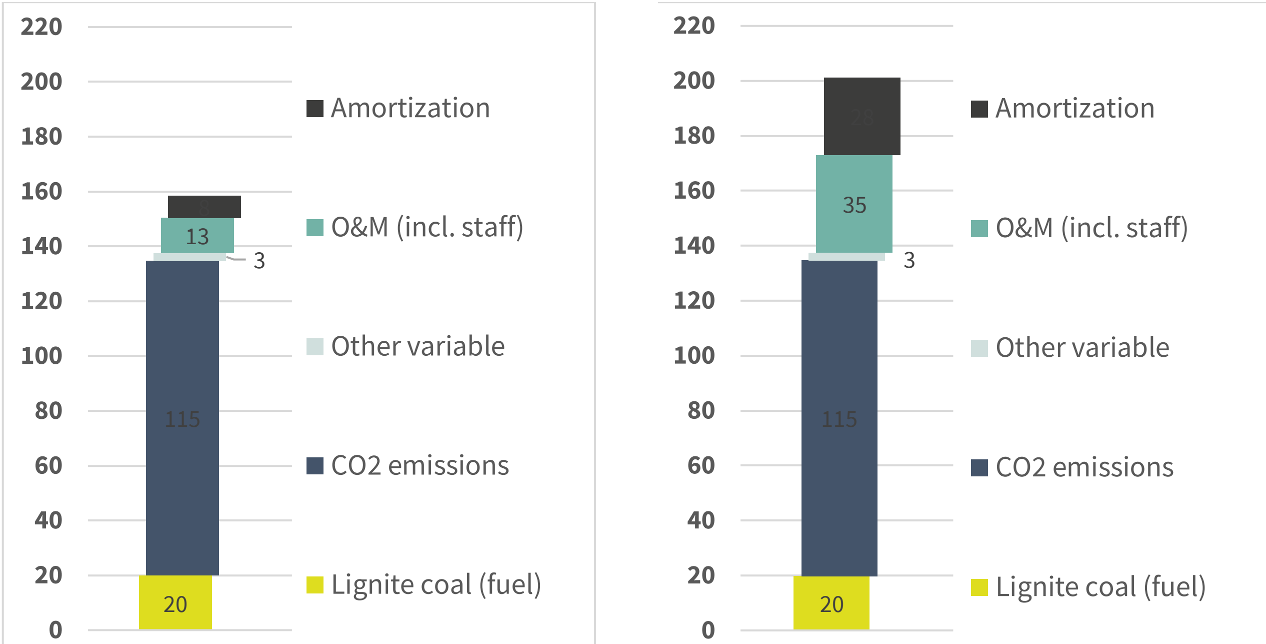
Table 3. Annual costs of Maritsa East 2 TPP, as approved by the EWCR.[28]

The 2023/2024 EWRC price application and decision[29] are based on annual electricity sales of 8 649 GWh, which reflects annual average output of 1000 MW or ≈ 70 per cent capacity utilisation. Together with the data from Table 4, this yields the specific electricity cost breakdown, presented in Figure 14a.

[27] Evaluated by the EWRC at a price of EUR 88.00/tonne.

[28] Energy and Water Regulatory Commission (EWRC), Price decision № Ц-14/30.06.2023, *EWRC,* 2023.

[29] Ibid.



a. Result with fixed costs allocated on 8649 GWh$_{net}$ *b. Result with fixed costs allocated on 2500 GWh$_{net}$*

Figure 14. Specific electricity cost [EUR/MWh] of Maritsa East 2 TPP according to the EWRC's 2023/2024 price decision.[30]

Since the above utilisation rate is considered to be unrealistic, the specific cost is also recalculated[31] for net electricity sales of 2500 GWh (≈ 20 per cent capacity utilisation), as shown in Figure 14b.

The resulting estimated unit electricity cost at the above parameters is:

- **EUR 159/MWh** at high capacity utilisation (8649 GWh/year), including EUR 8/MWh for amortisation
- **EUR 201/MWh** at low capacity utilisation (2500 GWh/year), including EUR 28/MWh for amortisation

Bobov Dol

The annual costs of the company are officially declared and approved by the EWRC. For the regulation period 2023/2024 their levels are as given in Table 4. These costs do not include the rate of return (margin/profit), nor the 5 per cent fee on electricity sales for the 'Security of the Electricity System' Fund.

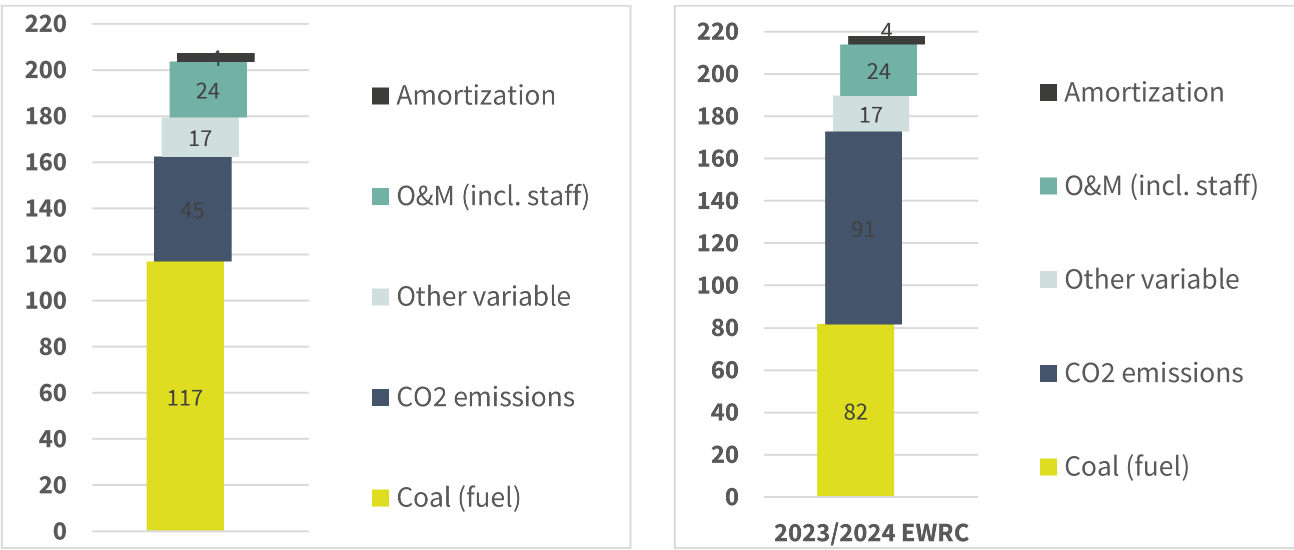
[30] Ibid.

[31] Assumptions: fixed O&M costs reduced by 20 per cent and allocated proportionally; variable costs remain unchanged and, optimistically, efficiencies and own needs do not deteriorate.

	Cost category	kBGN	kBGN
Variable	Fuels (coal, biomass and heavy oil)[32]	359 650	**551 110**
	Emissions allowances[33]	139 411	
	Consumables (limestone)	6 240	
	Water use	631	
	Electricity	6 009	
	Outsourced services	39 054	
	Ash deposition	115	
Fixed	Salaries, insurance and social	29 916	**86 232**
	amortisations	11 445	
	Maintenance	36 847	
	Other fixed	8 024	

Table 4. Annual costs of Bobov Dol TPP, as approved by the EWCR.[34]

The 2023/2024 EWRC price application and decision[35] for the plant are based on annual electricity sales of 1563 GWh. Together with the data from Table 4, this yields the specific electricity cost breakdown, as presented in Figure 15a.



a. Result with data as per the EWRC's 2023/2024 price decision   *b. Result with 10 per cent biomass assumptions*

Figure 15. Specific electricity cost [EUR/MWh] of Bobov Dol TPP.[36]

[32] Calculated using the weighted average unit price declared by the company (EUR 32.95/MWh_{fuel}).

[33] ≈ 810,000 t_{CO_2} declared by the company; evaluated by the EWRC at a price of EUR 88/tonne.

[34] Ibid.

[35] Ibid.

[36] Ibid.

The data in Table 4 and the respective result in Figure 15 raise some questions about the fuels' mix, its emission factors, the fuel prices and others (noted in 0). The declared emission quantities imply[37] the use of 50-60 per cent biomass (600-700 000 tonnes, with > 3 000 GWh energy content), and at the same time coal with very low emission factor. There is not enough public information to verify the above data or validate how the claimed weighted average fuel price reaches EUR –32.95/MWh$_{fuel}$.

Since this is not considered credible, we have presented a theoretical breakdown of the unit cost of electricity sold by Bobov Dol, in case of 10 per cent biomass in the fuel mix, and retaining most of the fixed and variable costs, which are not related to fuel and emissions. This is presented in Figure 15b.

The resulting estimated unit electricity cost is:

- **EUR 207/MWh** with the officially reported costs and production parameters, including EUR 4/MWh for amortisation
- **EUR 218/MWh** in the theoretical case with 10 per cent biomass, including EUR 4/MWh for amortisation.

Options for replacing coal with gas in power plants

The major technical approaches and technologies for replacing coal with gas (in power plants), which are relevant to this Report, are reviewed in Annex 1.

Implemented and planned coal-to-gas projects in Bulgaria

Varna TPP

Review of available information

Originally, the plant was a condensation coal-fired power plant. It has 6 blocks of 210 MW$_e$ each. After purchasing the plant from CEZ in 2017, the new owners gradually reconstructed 3 of the blocks (630 MW$_e$ altogether) to gas-fired by retrofitting the existing coal-fired boilers.

The plant has been among those awarded 'cold reserve' or capacity availability till 2022.

In 2021 the gross production was ≈ 700 GWh (≈ 7000 hours sum of the operation time of two blocks). In 2022 it was only ≈ 80 GWh (≈ 750 hours operation of one block only), due to the increase of gas prices.

In these years the part load efficiency declared by the company has been ≈ 34 per cent$_{gross}$ (≈ 32 per cent$_{net}$), operating at minimum average loads below 50 per cent.

It is not clear what is the nameplate nominal net electric efficiency on gas. According to reports submitted by the plant's management to the Executive Environment Agency, the units may reach 38-39 per cent gross efficiency. However, this information is insufficient to state whether any of them would comply with the

[37] Concluded by analogy with the company's 2022 Emissions Report data at the Executive Environment Agency, EEA, stating that annual quantities exceeding 800 000 tons of biomass (with 3 700 GWh net energy content) have been delivered and used at Bobov Dol TPP, representing two-thirds of the fuel mix.

threshold of < 550 g/kWh (one of the numerous conditions for installations to be feasible for capacity mechanism payments – as per Art. 22 of EU's Regulation 2019/943).[38]

Estimation of the specific electricity cost (on gas)

There is not enough public information to evaluate the production cost/price of the electricity from Varna TPP, especially regarding its fixed costs.

However, the variable specific cost of net electricity (similar to the SRMC) has been estimated based on the efficiencies given by the EWRC and Bulgaria's Executive Environment Agency (EEA). Net efficiency ranges between 32 and 36 per cent, depending on operating loads.

By September 2023:

- at gross gas price ≈ EUR 32.00/MWh_{HHV} (based on the regulated price of Bulgargas plus fees)
- at a CO_2 emission EU ETS price of EUR 88/t_{CO_2} (as used above in sections 0 and 0.)

the specific variable cost is estimated to be from **EUR 155/MWh_{net}** (η=36 per cent) to **EUR 175/MWh_{net}** (η=32 per cent).

By 2030 (with the assumptions described in sections 0 and 0), the specific variable costs are estimated to be almost the same: from **EUR 153/MWh_{net}** (η=36 per cent) to **EUR 172/MWh_{net}** (η=32 per cent).

These costs exclude fixed costs, such as staff and amortisation, rate of return, such as margin and profit, and the 5 per cent fee on electricity sales for the Security of the Electricity System Fund.

Maritsa East Power Plants

Review of available information

No specific information is available for planned investment regarding change of the fuel base of the large lignite power plants in the Maritsa East basin, apart from an obsolete version of the recovery and resilience plan from 2021,[39] where funding was allocated for connecting all of them to the existing gas transmission network of Bulgartransgaz EAD. In this document, the design and construction of 125 kilometres of DN1000 and DN700 pipelines for the region was estimated at a total of EUR 185.43 million.

No information was found, whether the concept was based on:

- operation with the existing energy production equipment after reconstructing it to gas-fired; or
- construction of completely new gas-fired (CCGT) capacities.

This project was dropped from the more recent versions of Bulgaria's recovery and resilience plan.

[38] European Parliament, Council of the European Union, REGULATION (EU) 2019/943 of 5 June 2019 on the internal market for electricity, *EUR-Lex,* 2019.

[39] Next Generation, Projects under the National Recovery and Resilience Plan of Bulgaria, Ver. 1.3 /15.10.2021, *nextgeneration.eu*, 2021.

Bobov Dol

Review of available information

In several interviews in 2023, the plant's manager stated that the installation of large gas turbines, ranging from 70 to 240 MW_e according to different reports, was being considered. However, no official proposals have been announced.

The only official investment proposal for transitioning from coal to gas, submitted in April 2021,[40] is broad in scope and comprises major subprojects:

- Connection to the Bulgartransgas gas network (via a ≈ 1.5-kilometre DN400 pipeline at 5 bar);
- Installation and commissioning of a gas system on-site at Bobov Dol;
- Installation and gas supply of 12 new starting burners on the three OB 650-040 steam boilers (replacing the existing burners on heavy fuel oil);
- Installation of four Wartsila 20SG34 gas piston engines, each with a capacity of 9.73 MW.

The latter of the subprojects to some extent represents a replacement of coal with gas, since the gas engines are likely to substitute some of the electricity production of the existing units, presently operating on a mix of coal and biomass. But the concept for the project could also change in order to balance the neighbouring PV plant currently under construction.

In December 2021, the regional environmental authorities officially decided that the Investment proposal does not require an environmental impact assessment.

Feasibility of reconstructing coal-fired units in Maritsa East and Bobov Dol plants to gas-fired

No official information is available for intentions of the coal-fired plants' management to plan reconstructing the existing boilers to gas-fired (except for the obsolete version of the recovery and resilience plan,[41] noted in 0).

Serious doubts in the profitability of such investment exist, in relation to the following issues:

- The expected electric efficiency of the existing units (on gas) is at least 10 per cent below that of the engines and > 20 per cent below that of a new CCGT. That translates to >25 per cent and >50 per cent higher variable production costs (fuel and emissions), respectively. Such big difference would prevent the reconstructed plant from being competitive in comparison with such capacities (in Bulgaria or abroad).

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[40] TPP 'Bobov dol', Investment proposal of for project 'Connection to the gas network of Bulgartransgas, commissioning of a gas system on the sit e of TPP Bobov dol, gas-supply of starting burners of steam boilers OB 650-040, and installation of 4 gas piston engines with capacity of 9.73 MW each', *RIEW Sofia,* 2021.

[41] Next Generation, Projects under the National Recovery and Resilience Plan of Bulgaria, Ver. 1.3 /15.10.2021, *Next Generation*, 2021.

- The existence, availability, and example of the gas-fired Varna plant (3 units x 210 MW_e each), which has already made the needed investments, but has minimum or no utilisation in recent months/years – since emission prices increased.
- A coal-fired unit reconstructed for direct operation on gas will have a nominal efficiency giving specific CO_2 emissions very close to the threshold value of 550 g/kWh. That (along with other requirements) represents a risk of not being eligible for receiving capacity availability payments.

For these and other reasons (exorbitant fixed costs, unsuited technology, etc.), this option is not analysed further in this report.

Selected options for the economic viability analysis

Maritsa East Power Plants – Combined Cycle Gas Turbine (CCGT)

With a view of the issues discussed in the previous section, the option studied for the Maritsa East Power Plants should comply with the following criteria:

- To be of size correspondingly large to that of the existing capacities and to the possible grid needs.
- To have electric efficiency that will comply with the requirement of < 550 g/kWh specific CO_2 emissions, so that to be eligible for receiving capacity availability payments after 2025.
- To have high electric efficiency, so that to mitigate the high prices of gas and ETS emission quotas, and thus to be competitive with respect to the variable costs of other production units, such as at the existing Varna plant.
- To have a technology allowing the replacement of gas by (green) hydrogen, if the latter becomes available in sufficient volumes and price-competitive.

The technology that best suits these requirements (offering high efficiency and reliability) is the CCGT. A size of 1000 MW_e has been selected for this study, which would normally be composed of 2÷4 units. Correspondingly, the conclusions will be equally valid for capacities above 500 MW, since specific CapEx, operational expenditure (OpEx), and efficiencies would change only marginally.

Bobov Dol – Internal Combustion Engines (ICEs)

Among other subjects, the investment proposal of the Bobov Dol[42] describes the installation of four gas-fired Wartsila 20SG3 engines with a total capacity of 39 MW_e.

There is not credible information on the criteria for choosing this technology, but it might be speculated that they are related to the manoeuvrability and good part-load electric efficiency of the engines (see Annex 1).

[42] TPP ‘Bobov dol’, Investment proposal of for project ‘Connection to the gas network of Bulgartransgas, commissioning of a gas system on the sit e of TPP Bobov dol, gas-supply of starting burners of steam boilers OB 650-040, and installation of 4 gas piston engines with capacity of 9.73 MW each’, *RIEW Sofia*, 2021.

The latter would make the new capacity suitable for balancing the company's 100 MW_p PV capacity, which is being built near the existing power plant.

Assumptions for the analyses

The prices of emissions, gas, and baseload electricity used in the following calculations and discussions are taken from a 2023 report by the Center for the Study of Democracy.[43] The values for the period from 2025 to 2040 are presented below, as the reference data is shown as 'Central' scenario. The ±20 per cent scenarios are presented and used for the purposes of the sensitivity analyses later in the present report.

CO_2 emissions

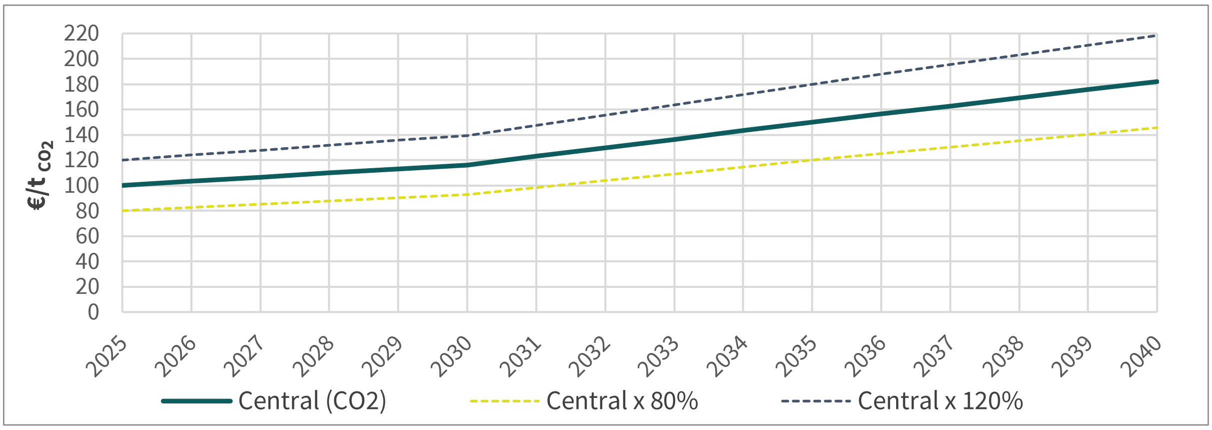

Figure 16: Annual average of CO_2 emission prices (EUR/tCO_2)[44]

With an average around EUR 85/t_{CO_2} in 2023, the ETS EUA price is projected to be around EUR 100/tonne in 2025 before reaching EUR 116/tonne in 2030, EUR 150/tonne in 2035 and EUR 182/tonne in 2040.

Gas

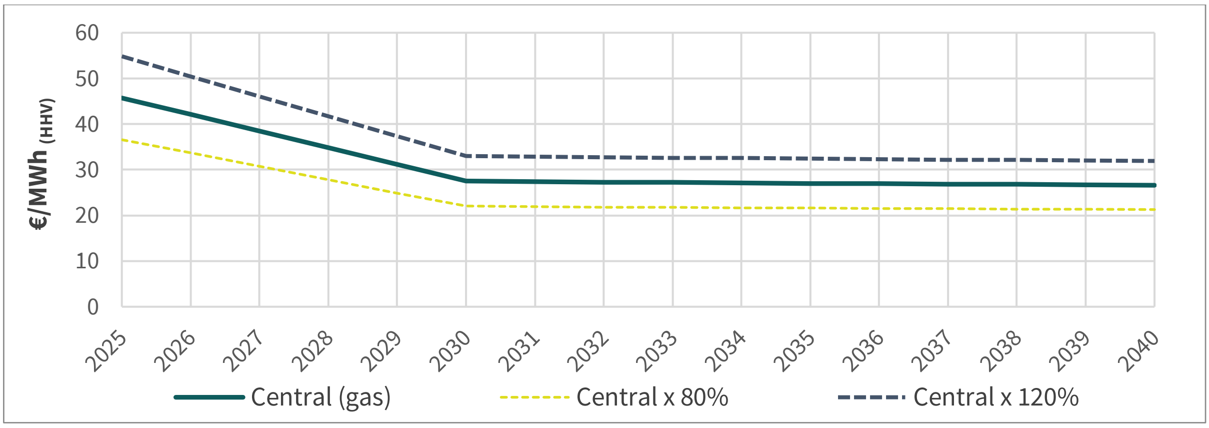

Figure 17: Annual average of wholesale price of gas (EUR/MWh)[45]

[43] Center for the Study of Democracy (CSD), 'Decarbonising the Bulgarian Power Sector', *CSD*, 2023.

[44] Ibid.

[45] Ibid.

The wholesale price of gas for large installations in the fourth quarter of 2023 is around EUR 30/MWh_{HHV}. The annual average for 2025 is forecast to increase to EUR 45.70/MWh and then drop to EUR 27.50/MWh in 2030, remaining relatively flat thereafter (EUR 26.50/MWh in 2040).

The forecast trend fits well with the results of the IEA's 2023 World Energy Outlook[46] and Energy Brainpool's 2060 EU Energy Outlook.[47] The latter sets the European market price at around EUR 40/MWh in 2025, settling at around EUR 23/MWh between 2030 and 2040. According to IEA, it settles at EUR 25 to 26/MWh between 2030 and 2050.

For these financial models, an additional cost of EUR 2/MWh for transmission and access fees is added to the above wholesale prices.

Price of baseload electricity

The baseload electricity price resulting from the REKK model[48] in CSD's report[49] is around EUR 122/MWh in 2025, dropping to ≈ EUR 82/MWh in 2030 and then gradually increasing to ≈ EUR 95/MWh in 2040.

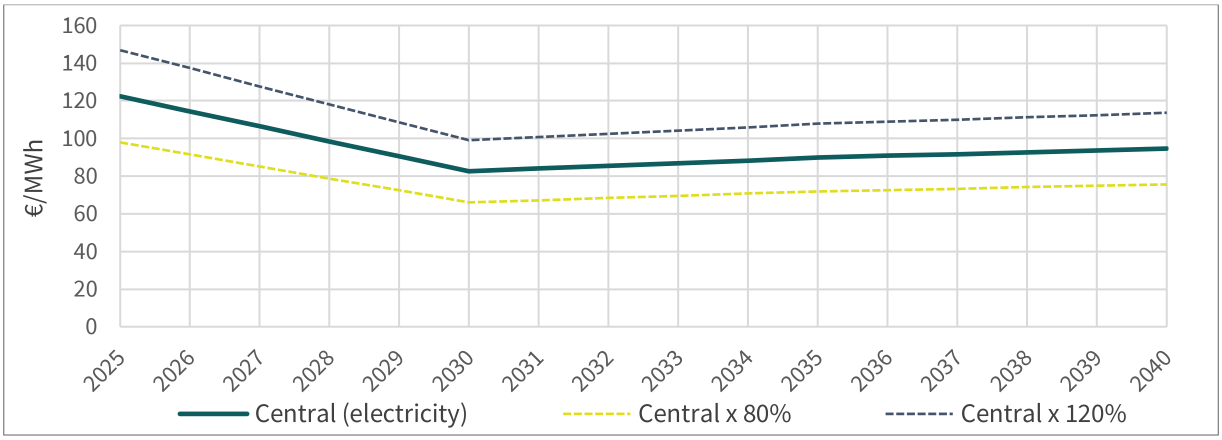

Figure 18. Annual average baseload electricity price projections for Bulgaria (EUR/MWh).[50,51]

Like gas price, this trend matches the results of Energy Brainpool's EU Energy Outlook 2060 report[52] for annual average prices, as depicted in Figure a. In the latter, EU prices are on average EUR 10/MWh lower, but the given variation interval for individual national markets covers the used reference prices (Figure 18).

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[46] International Energy Agency, World Energy Outlook 2023.

[47] Energy Brainpool, 'EU Energy Outlook 2060 – how will the European electricity market develop over the next 37 years?', *Energy BrainPool*, 2023.

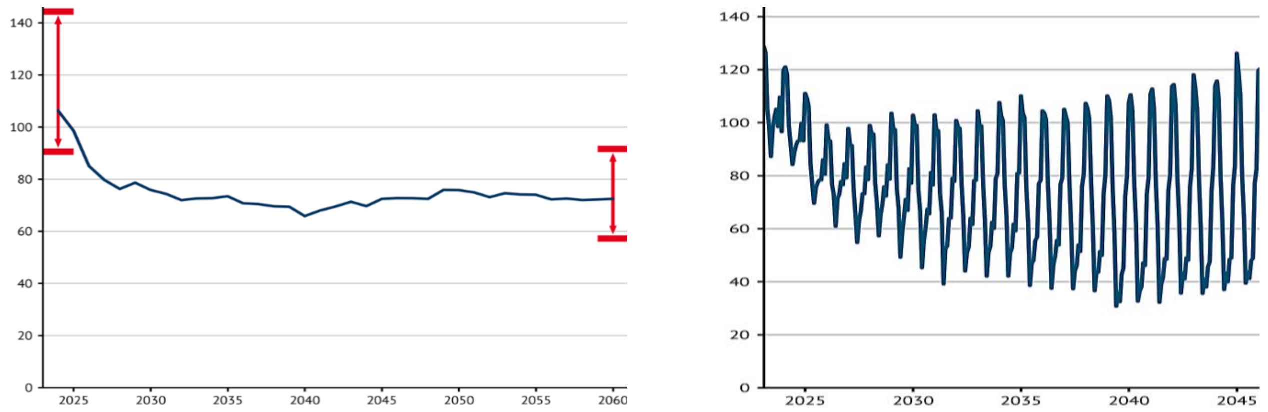
[48] Regional Center for Energy Policy Research (REKK), 'European Electricity Market Model', cited by Center for the Study of Democracy (CSD) in 'Decarbonising the Bulgarian Power Sector'.

[49] Center for the Study of Democracy (CSD), 'Decarbonising the Bulgarian Power Sector'.

[50] Ibid.

[51] Regional Center for Energy Policy Research (REKK), 'European Electricity Market Model', cited by CSD in 'Decarbonising the Bulgarian Power Sector', 2023.

[52] Energy Brainpool, 'EU Energy Outlook 2060 – how will the European electricity market develop over the next 37 years?', *Energy BrainPool*, 2023.



a) Annual average & range of variation in national markets   *b) Average monthly*

Figure 19. Baseload electricity price (EUR$_{2021}$/MWh) projection for the 27 EU Member States, Switzerland, Norway and the United Kingdom.[53]

Utilisation factor versus selling price

Gas-fired power plants have operate on a market basis by selling baseload electricity and products while balancing energy. With the forecast input cost levels of gas and CO_2 emission quotas (see above) and market price of baseload electricity (0) it cannot be expected that gas-fired installations shall run as baseload capacity (with full utilisation) and so their sale price shall not be equal to the baseload price.

As shown in Figure 10 and Figure 11, there are periods when market prices significantly surpass the annual average, which is when gas plants are expected to operate more often.

Additionally, the market price and utilisation (i.e. operating hours) are seemingly interdependent.

The two scenarios developed in CSD's report[54] via the REKK model[55] give very similar hourly distributions of electricity prices (Figure). These shall be used in the present study for estimating the utilisation factors of the studied new gas-fired power plant options versus the sale price.

[53] Josephine Steppat, 'EU Energy Outlook 2060 – how will the European electricity market develop over the next 37 years?', *Energy BrainPool GmbH & Co*, 2023.

[54] Center for the Study of Democracy (CSD), 'Decarbonising the Bulgarian Power Sector, CSD, 2023.

[55] Regional Center for Energy Policy Research (REKK), 'European Electricity Market Model', cited by CSD in 'Decarbonising the Bulgarian Power Sector'.

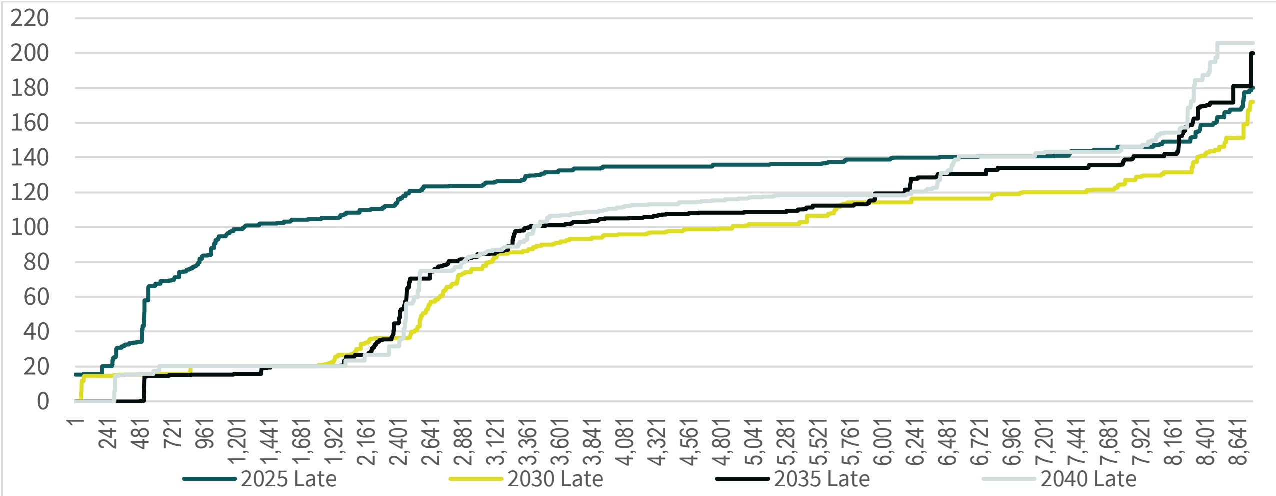


Figure 20. Hourly distribution of electricity prices (EUR/MWh) based on a 'late-coal-phase-out' scenario.[56]

An interpretation of Figure might be that an (infinitely flexible) power producer would be able to sell at prices ≥ EUR 140/MWh for around 2200 hours at ≈ 25 per cent utilisation in 2025 and 2040, but only at 5 per cent in 2030 and ≈ 10 per cent in 2035.

At the same time, the CSD report expects utilisation of gas-fired power plants to be in the range 17 to 20 per cent from 2025 till 2035 and then to decrease to ≈14 per cent in 2040.

The sensitivity of the economic viability of the studied gas-fired capacities as a function of their utilisation shall be included in the sensitivity analyses, starting from a base level of 20 per cent (covering the 0-40 per cent range).

For that purpose, based on the data from Figure, the annual average sale prices are calculated, corresponding to 10 per cent, 20 per cent, 30 per cent, and 40 per cent of the hours with the highest electricity price (Figure 22).

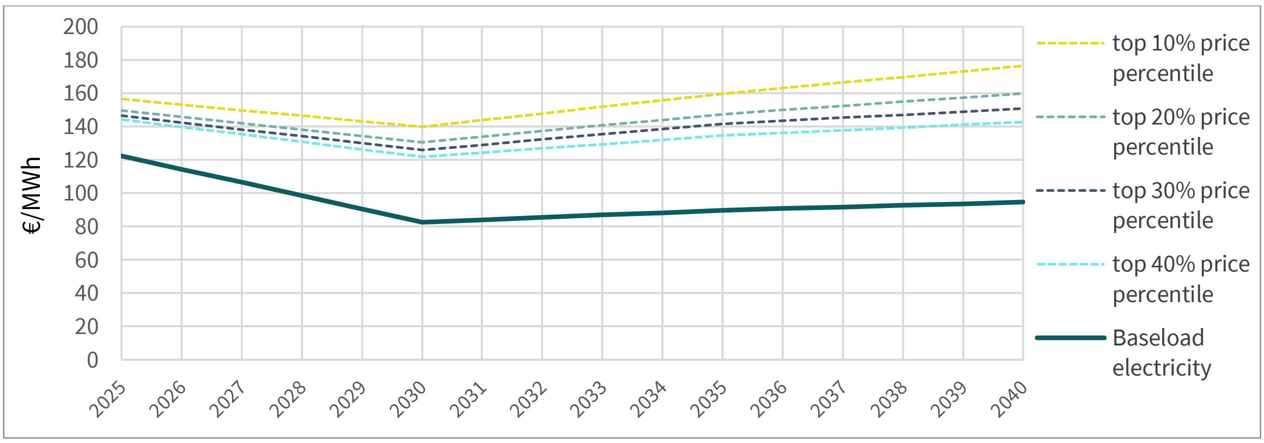


Figure 21. Annual average of the top 10 per cent, 20 per cent, 30 per cent and 40 per cent hourly prices between 2025 and 2040 [EUR/MWh] based on a 'late-coal-phase-out' scenario.[57]

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[56] Center for the Study of Democracy (CSD), '[Decarbonising the Bulgarian Power Sector](#)'.

[57] Ibid.

As should be expected, the average market price decreases with increased utilisation per cent. For example, in 2035 the spread between the average price for the 10 per cent of the year with the highest price (top 10 per cent percentile) is almost EUR 160/MWh while that for the 40 per cent percentile is less than EUR 135/MWh.

Capacity availability payments (by the TSO)

As per art. 21, par. 1, p. 21, of the Energy Act (as quoted in 0), it is not allowed to appoint availability capacity to producers (plants) that have a regulated price exceeding the forecast market price (for the following regulatory period) by more than 10 per cent. With the above price context, after 2025 gas-fired power plants will positively exceed these 110 per cent of regulated market price.

Furthermore, with recent developments of postponing or eliminating deadlines for shutting down coal-fired power plants in Bulgaria, it seems possible that some capacity mechanism might be allocated to Maritsa East 2.[58] That would reduce the need to allocate capacity to other (in this case gas-fired) plants.

On the other hand, studies ([59, 60]) show that after 2025 some 'room' shall exist for electricity from gas-fired plants. With a view of the latter, and for completeness of the analysis, the option of receiving capacity availability (for 4500 h/year at full capacity) shall also be considered.

By 2023 the price on the capacity market in Bulgaria is EUR 5.1/MWh (10 BGN/MWh). The sensitivity analysis will cover the range from EUR 6 to 14/MWh.

Applicability of guaranteed (by the state) power purchase

Apart from installations that are part of DHCs, gas-fired power plants are not part of the 'priority' producers and thus are not subject to guaranteed take-off of their electricity production.

Given the ongoing market liberalisation and the increasing emissions reduction targets, it is very unlikely that such a take-off will be enforced for electricity from fossil fuels.

Commissioning year of new gas-fired installations

Depending on the technology and the current status of the coal-to-gas replacement, the following shall be assumed as the most optimistic scenarios for the completion of the design, permitting, delivery, installation, and commissioning of the new generation units:

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[58] A legitimate form of state support for Maritsa East 2 (or the other lignite-fired plants) is not known. Payments under a capacity mechanism to Maritsa East 2 would not be compliant with Art. 22 of EU Regulation 2019/943. Bulgaria did not negotiate capacity mechanisms for the lignite plants by the respective deadlines in 2019.

[59] Ibid.

[60] Compass Lexecon, 'Decarbonisation options for the Bulgarian power sector', *AmCham,* October 2022.

Technology/Installation type	Project duration (minimum)	Commissioning year
CCGT installation (> 400 MW_e)	3 years	2027
Retrofitting a coal-fired TPP to gas	2 years	2026
Internal combustion engines (at the existing PP)	2 years	2026
Internal combustion engines at Bobov Dol TPP (already in progress)		2025

Table 5. Assumptions for the earliest possible commissioning year for new gas-fired installations.

CapEx for new gas-fired installations

Investments in new gas-fired installations are evaluated based on the specific CapEx values for the respective technologies (in EUR million/MW), as given by the Danish Energy Agency in the latest version of its catalogue Technology Data - Energy Plants for Electricity and District Heating Generation.[61]

For CCGT (>100 MW_e), this specific investment cost is EUR 0.88 million/MW (EUR 1 million/MW given by the IEA).[62]

For gas engines, the specific investment cost taken from[63] is EUR 0.95 million/MW.

For the installations, which are not greenfield and some of the infrastructure from existing plants can be used (e.g. cooling, power transformers grid connections, roads, etc.), these values are reduced by 15 per cent.

Additional CapEx is estimated for off-site infrastructure, namely gas supply pipelines.

Non-fuel OpEx for new gas-fired installations

The OpEx for the new installations is calculated using the reference values for fixed operations and maintenance (O&M) (EUR/MW_e/year) and variable O&M (EUR/MWh_e) for the respective technologies, as given by the Danish Energy Agency in version 13 of its catalogue Technology Data – Energy Plants for Electricity and District Heating Generation.[64]

Type of cost	Units	CCGT	Gas Engines
Fixed O&M (including staff)	EUR/MW_e/year	29,300	9750
Variable O&M	EUR/MWh_e	4.4	5.4

Table 6. Assumptions for O&M cost ratios for new gas-fired installations.[65]

[61] Danish Energy Agency, 'Technology Data - Energy Plants for Electricity and District Heating Generation' Ver. 0013, *Danish Energy Agency*, 2024.

[62] International Energy Agency, World Energy Outlook 2023.

[63] Danish Energy Agency, 'Technology Data - Energy Plants for Electricity and District Heating Generation' Ver. 0013.

[64] Ibid.

[65] Ibid.

Exclusion of fixed costs for current plants

The new installations are considered independent from the existing plant in terms of its present fixed costs. Otherwise, if the fixed costs of the existing companies are to be borne by the new gas-fired capacity, economic viability would be out of the question.

For example, the present fixed costs of Bobov Dol TPP, excluding amortisation, are ≈ EUR 38 million for a capacity of 630 MW_e. If the new gas-fired installation is considered as stand-alone, these fixed costs would be in the order of EUR 0.4 million, or ≈ 100 times lower for a 16 times smaller capacity (39 MW_e).

In the case of Maritsa East 2 TPP, the present fixed costs, excluding amortisation, are ≈ EUR 111 million for a capacity of 1630 MW_e, while for a capacity of 1000 MW_e the new CCGT installation is expected to have fixed costs in the order of EUR 30 million.

Efficiencies of new gas-fired installations

The annual average net electric efficiencies of the new installations are based on the reference values for the respective technologies – as given by the Danish Energy Agency in ver. 0013 of its catalogue entitled Technology Data – Energy Plants for Electricity and District Heating Generation,[66] and interpolated for the year 2025.

Apart from production efficiency, 1 per cent of transformer losses is applied.

Inflation

Inflation on non-fuel OpEx is assumed to be flat at 3 per cent per year. Reference prices for electricity, gas and CO_2 are taken from the respective sources and as such are not inflated.

Weighted average cost of capital (discount rate)

WACC = 4 per cent for calculating the financial indicators of the invested capital.

Lifetime and residual value

As per the assignment, the considered outlook for the new installations is till 2040 (gas should be of marginal significance after that). Therefore, the investments are amortised completely by 2040, with no residual value.

Use and sale/monetisation of heat energy

No utilisation of thermal energy (heat) from the electricity production installations is considered. Correspondingly, no additional incomes from selling/using such heat are entered into financial models.

[66] Ibid.

This assumption is based on the fact that existing heat utilisation in some thermal power plants is for drying the coal/biomass fuel for the steam boilers (such as at Bobov Dol) or for external coal-drying installations (Brikel). If such a plant switches to gas, irrespective of the approach, the need for drying the phased-out fuel ceases. Hence, the justification that this is a CHP plant becomes null and void.

DH installations and plants are beyond the scope of this study. Moreover, Bobov Dol and Maritsa East are not supplying networks of this kind.

Analysis of replacing coal with gas in selected cases

Maritsa East Power Plants (CCGT – 1000 MW_e)

Project parameters

Capacity:	1 000	MW_e	
Net Efficiency:	57	per cent	(gross production efficiency = 58.2 per cent)
CapEx:	EUR 859	million	
Fixed OpEx:	EUR 29.3	million/year	
Variable OpEx:	EUR 7.5	million/year	(for electricity production as per the 'Central' scenarios)

Estimation of the resulting specific electricity costs

The specific cost of net electricity, produced from the new installation – calculated year-by-year with the described input assumptions – is presented in Figure 22. For comparison, the annual baseload price and the top 20 per cent percentile are also displayed on the same chart.

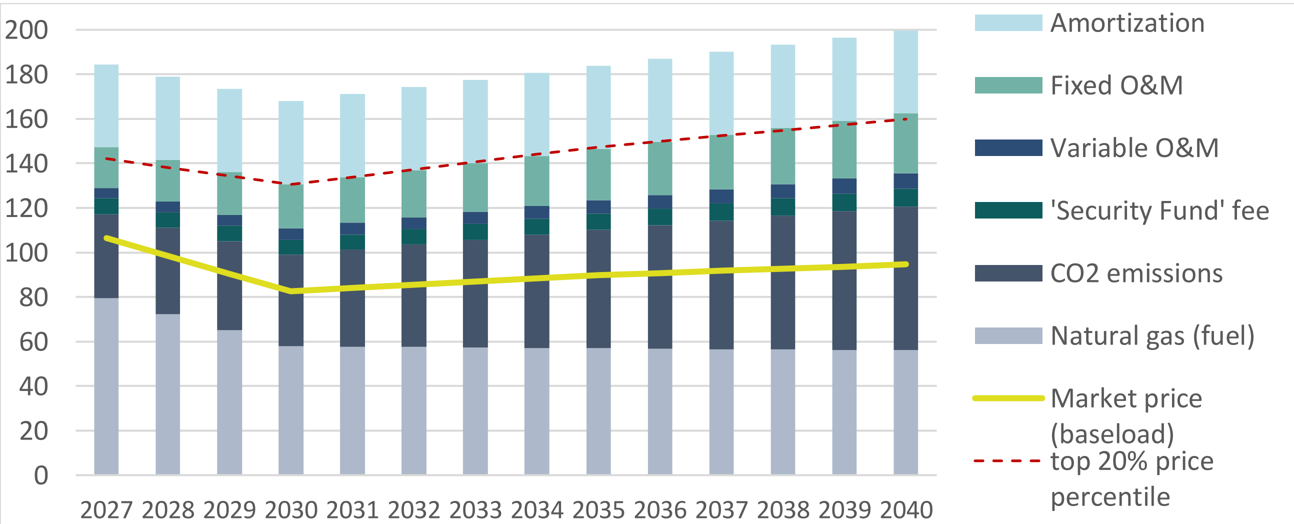

Figure 22. Specific electricity cost breakdown (EUR/MWh) for 1000 MW_e CCGT.

Evaluation of economic feasibility

It is obvious from the results in Figure that no profitability can be sought, since in each of the years the expected market price (for the top 20 per cent percentile) is below the operational cost of electricity. The same can be demonstrated also in case of 30 per cent utilisation.

In other words, in case of no support scheme, the project would generate operational loss with every hour of production, even without considering the investment amortisations.

The financial analysis gives the following results:

- Assuming the availability of payments for 4500 GWh (at EUR 10/MWh); that is, a theoretical extra income of EUR 45 million/year: **NPV = EUR –431 million, internal rate of return (IRR) < 0 per cent**;
- With no capacity availability payments: **NPV = EUR –841 million**, **IRR << 0 per cent**.

Sensitivity analysis

In this section the projects' NPV variation is calculated for some essential input parameters. The latter are listed in Table 7, together with the default (or central) assumed values and the respective sensitivity range.

Input Parameter	Unit	Default Value	Sensitivity range
Total turnkey CapEx	EUR million	859	+/-10 per cent
Scenario - electricity sale price	-	Central (electricity)	+/-20 per cent
Scenario - gas price	-	Central (gas)	+/-20 per cent
Scenario - CO_2 emissions price	-	Central (CO2)	+/-20 per cent
Availability capacity price assumption	EUR/MW*h	10.00	+/-40 per cent
Fee on electricity sales ('Security of EES' Fund)	per cent	5.0 per cent	0 per cent or 5 per cent
Utilisation factor (demand) of installed capacity	per cent	20 per cent	0 per cent ÷ 40 per cent
Average gross electrical efficiency	per cent	58.2 per cent	+/-2 per cent

Table 7. Parameters and ranges tested in the sensitivity analysis for the 1000 MW CCGT.

Each of the tables below gives the NPVs for all combinations of tested values of the corresponding two parameters. The thick lines highlight the 'central' or baseline scenario or value of the input parameter.

With capacity availability payments

SENSITIVITY ANALYSIS

			Total turnkey CAPEX, M€				
			-10%	-5%		+5%	+10%
NPV [mil. €] =		-431	773	816	859	902	945
Utilization factor (demand) of installed capacity, %	-20%	0%	-662	-704	-745	-786	-828
	-10%	10%	-425	-466	-507	-549	-590
		20%	-349	-390	-431	-473	-514
	+10%	30%	-313	-354	-395	-436	-478
	+20%	40%	-355	-396	-437	-479	-520

		Availability capacity price assumption, €/MW*h				
		-40%	-20%		+20%	+40%
NPV [mil. €] =	-431	6.00	8.00	10.00	12.00	14.00
Scenario - Electricity sale price	Central (electricity)	-595	-513	-431	-349	-267
	Central x 80%	-1,004	-922	-840	-758	-676
	Central x 120%	-187	-105	-23	59	141

		Scenario - Gas price		
NPV [mil. €] =	-431	Central (gas)	Central x 80%	Central x 120%
Scenario - CO_2 emissions price	Central (CO_2)	-431	-260	-603
	Central x 80%	-286	-114	-457
	Central x 120%	-577	-406	-749

		Average gross electrical efficiency, %				
		-4%	-2%		+2%	+4%
NPV [mil. €] =	-431	54.2%	56.2%	58.2%	60.2%	62.2%
Fee on electricity sales ('Security of EES' Fund), %	0%	-446	-383	-324	-269	-218
	5%	-553	-490	-431	-377	-326

Figure 23. Sensitivity analysis results for the NPV of 1000 MW_e of CCGT (EUR million).

In all shown combinations of the studied ranges of parameters, the project NPV is negative, except for the combination of high capacity availability prices and 20 per cent higher electricity market prices than assumed in the 'Central' scenario. The latter means selling at a top 20 per cent percentile electricity price of ≈ EUR 174/MWh on average for the period in question.

Without capacity availability payments

In all tested scenarios and combinations, the NPV and IRR of the project are strictly negative, ranging from EUR –430 million to EUR –1250 million.

Bobov Dol (39 MW$_e$ internal combustion engines)

Project parameters

Capacity:	39.0	MW$_e$	(as per investment proposal)
Net Efficiency:	46.0	per cent	(gross production efficiency = 47.4 per cent)
CapEx:	EUR 33.0	million	
Fixed OpEx:	EUR 0.38	million/year	
Variable OpEx:	EUR 0.36 million/year		(for electricity production as per the 'Central' scenarios)

Estimation of the resulting specific electricity costs

The specific cost of net electricity generated by the new installation – calculated year-by-year with the described input assumptions – is illustrated in Figure 24.

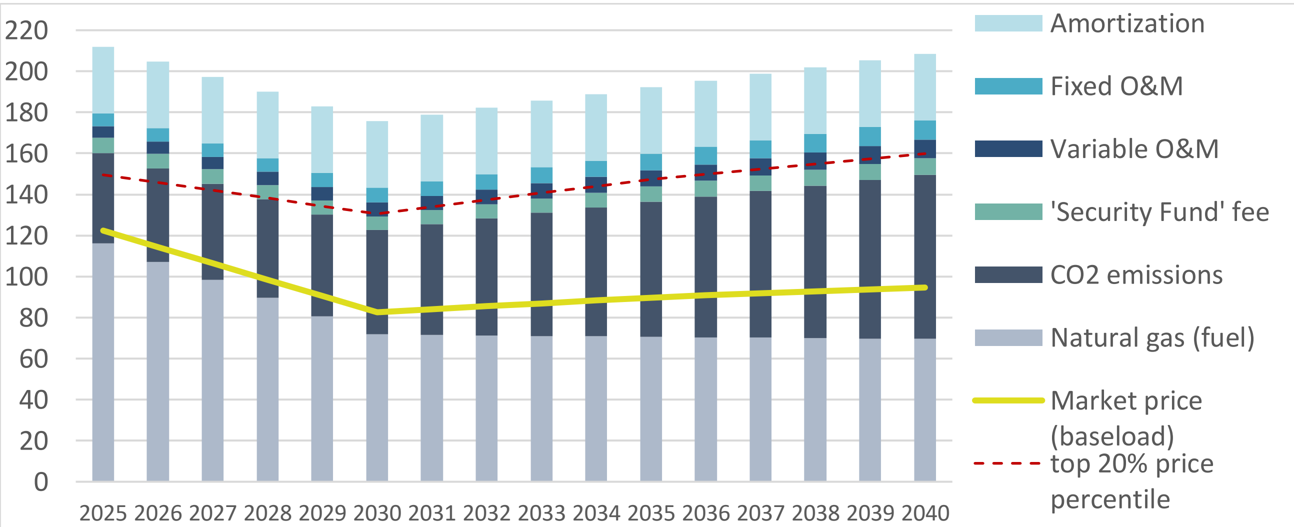

Figure 24. Specific electricity cost breakdown (EUR/MWh) for Bobov Dol TPP based on new ICEs (39 MW$_e$).

For comparison, the annual baseload price and the top 20 per cent percentile are also displayed on the same chart.

Evaluation of the economic feasibility

It is obvious from the results in Figure that no profitability can be sought, since in each of the years the expected market price (for the top 20 per cent percentile) does not even cover the variable cost of electricity. In other words, in case of no support scheme, the project would generate operational loss with every hour of production, even without considering the investment amortisations and fixed O&M. Thus, a major CapEx reduction (possibly buying used equipment) would not lead to overall profitability.

Another interpretation of the result in Figure is that with increasing the utilisation of the engines, the financial indicators of the project deteriorate (as demonstrated in the Sensitivity analysis below).

The financial analysis gives the following results:

- Assuming the availability of payments for 176 GWh (at 10 EUR/MWh); that is, a theoretical extra income of EUR 1.76 million/year: **NPV = EUR –25 million**, **IRR < 0 per cent**;
- With no capacity availability payments: **NPV = EUR –43 million**, **IRR << 0 per cent**.

Sensitivity analysis

In this section the projects' NPV variation is calculated for some essential input parameters. They are listed in Table 8, together with the default (or central) assumed values and the respective sensitivity range.

Input Parameter	Unit	Default Value	Sensitivity range
Total turnkey CapEx	EUR million	33	+/-10 per cent
Scenario - electricity sale price	-	Central (electricity)	+/-20 per cent
Scenario - gas price	-	Central (gas)	+/-20 per cent
Scenario - CO_2 emissions price	-	Central (CO2)	+/-20 per cent
Availability capacity price assumption	EUR/MW*h	10	+/-40 per cent
Fee on electricity sales ('Security of EES' Fund)	per cent	5 per cent	0 per cent or 5 per cent
Utilisation factor (demand) of installed capacity	per cent	20 per cent	0 per cent ÷ 40 per cent
Average gross electrical efficiency	per cent	47.4 per cent	+/-2 per cent

Table 8. Parameters and ranges tested in the sensitivity analysis for the 39 MW_e engines at Bobov Dol TPP.

With capacity availability payments

SENSITIVITY ANALYSIS

			Total turnkey CAPEX, M€				
			-10%	-5%		+5%	+10%
NPV [mil. €] =		**-25**	**0.00**	**0.00**	**33.00**	**0.00**	**0.00**
Utilization factor (demand) of installed capacity, %	-20%	**0%**	*-16*	*-17*	*-19*	*-21*	*-22*
	-10%	**10%**	*-16*	*-17*	*-19*	*-20*	*-22*
		20%	*-22*	*-23*	*-25*	*-27*	*-28*
	+10%	**30%**	*-30*	*-31*	*-33*	*-34*	*-36*
	+20%	**40%**	*-40*	*-42*	*-44*	*-45*	*-47*

		Availability capacity price assumption, €/MW*h				
		-40%	-20%		+20%	+40%
NPV [mil. €] =	**-25**	**0.00**	**0.00**	**10.00**	**0.00**	**0.00**
Scenario - Electricity sale price	**Central (electricity)**	*-32*	*-29*	*-25*	*-21*	*-18*
	Central x 80%	*-50*	*-46*	*-42*	*-39*	*-35*
	Central x 120%	*-15*	*-11*	*-7*	*-4*	*0*

		Scenario - Gas price		
NPV [mil. €] =	**-25**	**Central (gas)**	**Central x 80%**	**Central x 120%**
Scenario - CO2 emissions price	**Central (CO_2)**	*-25*	*-15*	*-35*
	Central x 80%	*-18*	*-8*	*-27*
	Central x 120%	*-32*	*-23*	*-42*

		Average gross electrical efficiency, %				
		-2%	-1%		+1%	+2%
NPV [mil. €] =	**-25**	**-2.0%**	**-1.0%**	**47.4%**	**1.0%**	**2.0%**
Fee on electricity sales ('Security of EES' Fund), %	**0%**	*-24*	*-22*	*-20*	*-19*	*-17*
	5%	*-29*	*-27*	*-25*	*-23*	*-21*

Figure 25. Sensitivity analysis results for the NPV of 39 MW_e gas engines (EUR million).

In all shown combinations of input parameters’ values, the project NPV is negative (see Figure 25).

In particular, it can happen that the sensitivity to CapEx is so low that even when factoring in 50 per cent lower project investment costs (e.g. installing used equipment), positive overall financial results shall not be reached.

Without capacity availability payments

In all tested scenarios and combinations, the NPV and IRR of the project are strictly negative, ranging from EUR –25 million to EUR –65 million.

Discussion of the results

With capacity availability payments

With all other assumptions in place, in order to achieve an NPV > 0 for the considered period of 14 to 16 years:

- the 1000 MW_e CCGT installation at Maritsa East currently being considered would require ≈EUR 1.3 billion in capacity (or other form of) support. That equals receiving full capacity availability payments for > 6 months/year at a price of ≈ EUR 21/MWh.
- This annual capacity quantity (4.5 TWh) is not considered realistic for the analysed period. At the same time the price of EUR –21/MWh exceeds the current one 4 times, and the baseline assumption twice.
- the 39 MW_e gas-engine installation at Bobov Dol TPP currently being considered would require EUR 68 million in capacity, or another form of, support. That equals receiving full capacity availability payments for > 6 months per year at a price > EUR 24/MWh. This capacity availability price exceeds the current one almost 5 times, and the baseline assumption 2.5 times.

Without capacity availability payments

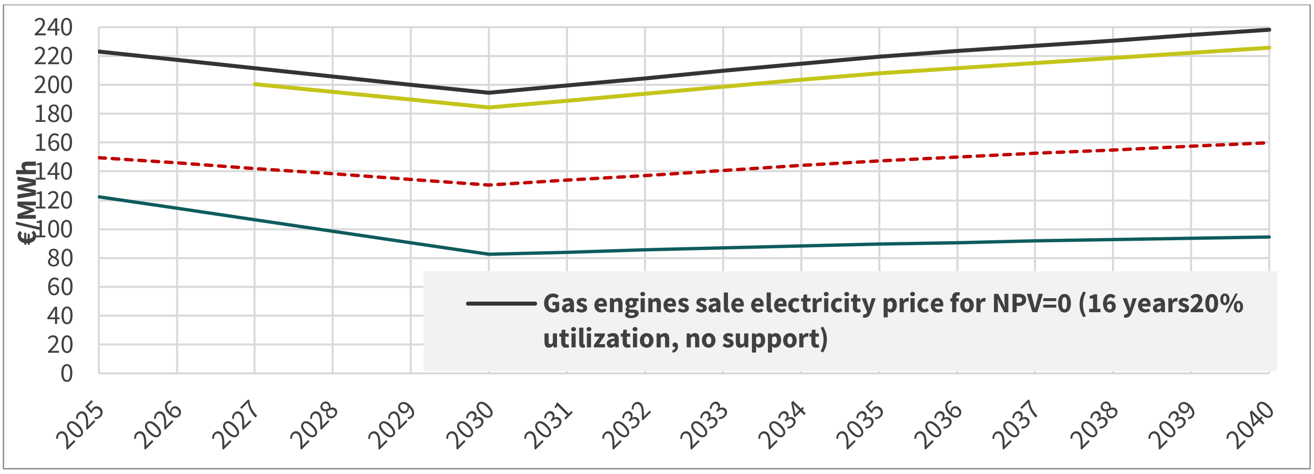

Figure 26. Average gaps (EUR/MWh) between market prices and 'NPV=0 sale prices' (studied cases with no support).

In order to achieve an NPV > 0, the case of a 1000 MW_e CCGT installation at Maritsa East TPPs would require an average sale price exceeding EUR 204/MWh at 20 per cent utilisation.[67] Such price levels exceed the 'top 20 per cent market price percentile' by 40 per cent, and the expected baseload prices by 124 per cent above (see Figure 26).

Similarly, for the 39 MW_e gas engines in Bobov Dol TPP to achieve an NPV > 0, the average sale price for the considered period would need to exceed EUR 215/MWh at 20 per cent utilisation. The former would be ≈50 per cent above the 'top 20 per cent market price percentile', and ≈140 per cent above the expected baseline market prices. At 10 per cent utilisation, the respective average sale price required would be > EUR 275/MWh.

Potential implications of a gas lock-in

Considering that gas will need to be phased out to align with the European Green Deal and climate targets, potential major investments in gas infrastructure and other assets (e.g. energy production capacities) are to be viewed as a potential risk for locking-in with this energy source.

Such a lock-in could result in the following significant negative economic consequences[68] for Bulgaria:

- Energy price volatility (gas price being subject to drastic fluctuations due to geopolitics or market dynamics)
- Market concentration (in dominant suppliers, as Gazprom used to be for decades)
- Inefficient allocation of resources (concentration in the gas sector rather than diversifying into renewable energy sources)
- Stranded assets (diminishing value of investments in gas infrastructure, due to the transition to sustainable energy sources – leading to financial losses for investors.)
- Depletion of carbon budgets and detrimental effects on climate change mitigation efforts.

In Bulgaria the DH sector relies primarily on gas and is responsible for most of the gas-fired electricity production. On the other hand, the country's power sector as a whole is among the EU's least dependent on gas – as discussed in 0 the share of this fuel source is limited (5-8 per cent).

Electricity production from gas is expected to increase after the closure of the coal-fired TPPs. However, due to the high variable costs, the utilisation of gas capacities is expected to remain low.[69, 70]

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[67] For 10 per cent utilisation, the resulting average sale price needed to reach NPV = 0 would exceed EUR 280/MWh. To put things in context, for a CCGT in the EU, the IEA, World Energy Outlook 2023 scenarios give LCOE values of EUR 220 to 230/MWh at 25 to 20 per cent utilisation for 2022 and EUR 270/MWh at 10 per cent utilisation for 2030.

[68] Energy 5, Natural Gas Lock-in Effect Economic Implications, *Energy5*, 8 September 2023.

[69] Center for the Study of Democracy (CSD), 'Decarbonising the Bulgarian Power Sector'.

[70] International Energy Agency, World Energy Outlook 2023.

Moreover, with a view to the following:

- the project for supplying the Maritsa East TPPs with gas was dropped from the recovery and resilience plan and is not publicly promoted by any of the major stakeholders;
- in October 2023 the Bulgarian government officially announced the start of (and allocated initial funding for) the project for construction of Blocks #7 and #8 (2 x 1 150 MW_e) in Kozloduy NPP;[71]
- in November 2023 the Minister of Energy confirmed that at least 50 per cent of the capacity of the Chaira pumped storage plant is planned to be put back in operation in 2025;

we conclude that Bulgaria's power sector is therefore not currently in danger of a major gas lock-in.

However, attention should be paid to the significant investments in gas infrastructure projects (recent and ongoing), e.g.:

- TurkStream transmission pipeline project: ≈EUR 1300 million
- Greece–Bulgaria gas interconnector (IGB): ≈EUR 250 million
- Bulgaria–Serbia gas interconnector (IBS): ≈EUR 90 million
- Chiren underground storage expansion: ≈EUR 310 million

The contract with Turkish state gas operator Botas, signed in December 2022, allegedly[72] contains clauses for EUR 1.9 billion 'take-or-pay' fees for the duration of the 13-year deal.

It can be argued to what extent each of these projects and contracts strengthens and diversifies Bulgaria's energy security, what is its economic justification, and whether it would be applicable to green hydrogen in the future, given the unlikelihood of it being available in such volumes at an affordable price.

Still, these five examples alone represent a EUR 4 billion commitment to the future of gas transmission, storage and consumption in Bulgaria and the region. The size of this commitment is huge in comparison with the other investments in Bulgaria's energy sector, being comparable only with that for the abovementioned nuclear units. For that reason, and since long-term contracts and investments in infrastructure are the most typical means for 'achieving' gas lock-in, the subject should be carefully observed and controlled.

[71] In the fourth quarter of 2023, the Bulgarian parliament voted to invest in the Westinghouse AP1000 units, providing the company responsible for the project with EUR 750 million. However, by the end of 2023, the rest of the financing has not been secured, and the economic justification for the project became unclear. In recent decades, Bulgaria has attempted to launch new nuclear unit projects, which were later scrapped due to a lack of investment, guaranteed electricity demand, and financial feasibility.

[72] Ivaylo Stanchev, Bulgaria to pay BGN 3.8 billion to Turkey under President Radev's gas deal, *Capital.bg*, 28 July 2023.

Comparing the economic impact of replacing coal with renewables

Possible solutions for RES replacement of the electricity from coal-fired power plants

Among the possible RES technologies for electricity production, the following are considered to have potential to replace the electricity from coal-fired power plants:

PV and Onshore wind with battery storage

PV and wind capacities, along with their production quantities, in Bulgaria are expected to increase manifold in the coming decades as the country pursues its climate-related objectives and commitments.[73,74]

However, under local conditions, these RESs are not suitable for use as stand-alone base sources, nor as manoeuvring/regulation capacities. That is why, on a system level, they should be matched with storage capacities in order to mitigate the uneven time distribution of their production.

Presently the price of batteries makes their inclusion financially unfeasible for investors, and this is not expected to change in the next years. Electricity storage capacities are to be co-financed under the recovery and resilience plan, but their size will be insufficient in relation to the thousands of megawatts of PVs.

Nevertheless, PV and wind installations are to become one of the major electricity sources in the country in the coming decades, especially when the appropriate storage capacities are repaired in the case of the existing pumped storage plant and implemented batteries.

Pumped storage hydro power plants

These are not entirely renewable, but with a round trip efficiency in the order of 80 per cent, they can be a useful substitute of coal-fired power plants with respect to grid balancing.

With the abovementioned plans for repairs of 'Chaira' PSHPP, this technology has the potential to play a major role after 2030 – especially with the rapidly increasing PV capacities, which need balancing.

Biomass-fired power plants

Technically speaking, biomass can partially replace coal in power plants, in some cases even after technological modifications of the existing boilers. Such a replacement would enable avoiding their current huge emission costs (see example in Figure 14, but is subject to certain serious limitations:

- Biomass resources are not accessible and feasible in quantities comparable to the present lignite consumption;

[73] Center for the Study of Democracy (CSD), 'Decarbonising the Bulgarian Power Sector'.

[74] CLEVER (a Collaborative Low Energy Vision for the European Region) – Results for Bulgaria, *clever.eu,* 2023.

- Utility scale power production from biomass combustion is disputable from environmental point of view, especially concerning forest biomass. Large groups of scientists agree that energy production from wood leads to 2-to-3 times higher initial carbon emissions than using fossil fuels;[75]

- With a view of the latter, biomass combustion installations may be included in the Emissions Trading System in the future, thus eliminating the economic grounds for investing in them;

- Biomass has low energy density and therefore its transportation would be expensive and with significant environmental impact.

Therefore, it is considered that there is a rather limited and uncertain potential for increasing the share of biomass in Bulgaria's electricity balance – based on biomass from industrial and agricultural origin, used in suitably located medium-sized CHP installations.

Renewable hydrogen

With the increasing PV and wind capacities in the EU in the next decades, the production cost of renewable (green) hydrogen is expected to decrease substantially (down to EUR 2 to 2.50/kg in most EU countries in 2040).[76]

However, within a horizon till 2050 none of the reviewed studies (including[77,78,79]) expect hydrogen to become a feasible fuel source with significant contribution for electricity production.

Instead, it is considered that green hydrogen will play a more important role in replacing fossil fuels in transportation, and some industrial processes.

Geothermal

Geothermal energy can be used for electricity production, but in Bulgaria its potential is more suitable for heat utilisation – due to its relatively low temperatures, low spatial density, and limited capacities (in terms of flowrate and thus energy).

Even under these local conditions, there are technologies that can (from technical point of view) produce electricity from geothermal energy – for example the Organic Rankin Cycle (ORC). However, the economic viability of producing electricity with ORC is also limited due to the high specific CapEx and the low efficiency at the available resource temperature levels.

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[75] Woodwell Climate Research Centre, Letter Regarding Use of Forests for Bioenergy, *Woodwell Climate Research Centre,* 11 February 2021.

[76] PwC, The green hydrogen economy: Predicting the decarbonisation agenda of tomorrow, *PwC*, 2023.

[77] Center for the Study of Democracy (CSD), 'Decarbonising the Bulgarian Power Sector'.

[78] Energy Brainpool, 'EU Energy Outlook 2060 – how will the European electricity market develop over the next 37 years?', *Energy BrainPool*, 2023.

[79] CLEVER (a Collaborative Low Energy Vision for the European Region), Results for Bulgaria, *clever.eu,* 2023.

As a whole, the characteristics of Bulgaria's geothermal energy sources make their utilisation more reasonable for heat (decentralised space heating of buildings, DH and industrial process heat), while the potential as a resource for electricity production is negligible on a country level.

Comparison of the benefits from replacing coal with RES versus gas

The expected EU market price of electricity from PV and onshore wind between 2023 and 2050 (according to[80,81,82]) are within the range of EUR 30 to 50/MWh and EUR 50 to 70/MWh, respectively.

These price levels are lower even than the estimated specific emission costs in the studied cases for producing electricity from gas (see Figure 22). Furthermore, in these figures it can be seen that sale prices above EUR 200/MWh would be needed to bring profitability for the considered gas-fired projects.

The economic analyses in chapter 0 of this report demonstrate that on a project level investing in electricity production from gas will be unfeasible under the studied cases, assumptions and ranges of input variables.

On a country level, electricity production from RES brings the following additional long-term benefits, compared to potential replacement of coal with gas:

- Avoidance of the dependence on imported primary energy (gas) and the related geopolitical risks;
- Avoiding the costs for gas imports and of the risks, associated to their volatility;
- Avoided CO_2 emission costs;
- Focusing the investments on local and sustainable electricity production capacities;
- Reduced environmental impact, thanks to avoided CO_2, CH_4, and NO_X emissions;
- Reduced/avoided adverse health effects on the population;
- Avoidance of gas lock-in (and the related risks);
- Avoided investments in conversion to a fossil fuel, which shall also need to be phased out in the next decade;
- Decentralised generation, reducing the vulnerability of relying on a few large facilities.

On the other hand, PV and wind – new RES which are expected to play a major role on a national level – fall behind gas-fired power plants in the following aspects:

- Predictability and availability of production in terms of capacity and time;
- Manoeuvrability for the purposes of grid balancing/regulation;

[80] International Renewable Energy Agency (IRENA), 'Renewable power generation costs in 2022', *IRENA,* 2022.

[81] Energy Brainpool, 'EU Energy Outlook 2060 – how will the European electricity market develop over the next 37 years?', *Energy BrainPool*, 2023.

[82] International Energy Agency, World Energy Outlook 2023.

- System frequency balancing by rotating mass inertia, proportion between rotating mass power sources and RES in order to secure system stability.

Therefore, in order to sustain the operational stability of its electric grid, Bulgaria needs to carefully plan the transition to RES, with parallel development of the storage and balancing capacities, as well as the cross-border transmission lines (for covering peak loads with imported electricity).

Annex 1. Technical approaches for replacing coal with gas

Reconstruction/replacement of existing coal-fired boilers to gas-fired

Brief technology description

Following the development of heat and power sources in Bulgaria, the initial design has been based on coal, later replaced by heavy oil, and then by gas – in order to face the growing environmental requirements, especially nearby urban zones. Therefore, with the exception of the TPPs at Rouse, Pernik and Sliven, all DH CHP plants have transitioned to gas. The only condensing power plant reconstructed to replace coal with gas is Varna TPP.

The most direct reconstruction approach impacts the steam generator burners replacement, re-dimensioning of heat exchanging plates and flue gas tract as a whole (and ash equipment/system removal). In some cases, it is more feasible (and compliant with contemporary environmental requirements), to replace the whole coal steam generator with a new gas-fired, supplying the required steam parameters (capacity, pressure and temperature) to supply the existing turbo-generator(s). In this case the power production capacity is retained as it was on coal (as in the case of the Varna TPP units).

The approach described above is not popular, because of its low resulting efficiency. Usually it is more feasible to replace the coal boiler with a gas turbine in order to increase the overall unit efficiency and enlarge its' power production capacity. In this way, the coal-fired unit becomes a CCGT unit. There are several schemes of connection the gas turbine, for heat utilisation, to the existing steam turbine (e.g. topping, boosting and parallel repowering).

Depending on the selected option, the cost and the needed time for implementation of the coal-to-gas reconstruction vary. However, in all cases the process is technically challenging due to the custom redesign needed in order to fit the specifics of the existing equipment to the new scheme, requirements, etc.

Advantages

In general, such transformation has several advantages.

- Reduction of investment costs, using residual resource of the rest of equipment of the power unit;
- Reduction of operating and maintenance costs of the power unit, the operational and maintenance costs for coal fuel process facilities are eliminated;
- The manoeuvrability of the steam generator and, respectively, of the entire unit is improved;

- The overall efficiency of the unit is improved (thanks to reduced own needs and higher fuel efficiency of steam generator);
- Significant reduction in local environmental impacts using gas versus coal (SO_x, FDP).

The above advantages are especially valid for CHP units nearby and connected to the heating networks of large cities, motivated mainly by improving the living environment.

Disadvantages

Considering the specifics of the Bulgarian energy sector, the reconstruction of baseload generating capacities from coal to gas poses disadvantages and risks, such as.

- Low electric efficiency of the unit, compromising its financial viability (unless gas and emission prices decrease drastically);
- High specific CO_2 emissions factor (g_{CO_2}/kWh_e) of the unit, endangering its eligibility to availability capacity allocation;
- Possible high NOx concentrations in the flue gases, that have adverse health impacts, unless a proper flue gas treatment installation is in place;
- Technical risks, related to the adaptation of the specific old and new equipment in the new scheme;
- Financial risk for investments, related to possible future restrictions on the use of fossil gas in power generation;
- Expensive and manufacturer specific maintenance (in case of including gas turbine in the scheme)

Internal combustion engines

Brief technology description[83]

A gas engine for co-generation of heat and power drives an electricity generator for the power production. At the current time net electrical efficiency up to 45-48 per cent can be achieved by this technology. The engine cooling water (engine cooling, lube oil and turbocharger intercooling) and the hot exhaust gas can be used for heat generation, e.g. for DH or low-pressure steam. In DH systems with low return temperatures both sensible and latent heat in the exhaust gas can be recovered by using a condensing cooler as the final cooling of the flue gasses and a total efficiency of approx. 96-98 per cent can be reached. If applying heat pumps for extra cooling of the exhaust gas system, 5-7 per cent higher total efficiency can be reached.

Typical capacities

5 kW_e to 10 MW_e per engine

[83] Most of the information in this chapter (non-specific to Bulgaria) is from the following source: 'Technology Data - Energy Plants for Electricity and District Heating Generation' Ver. 0013, issued by the Danish Energy Agency.

Regulation ability and other power system services

Gas engines can start faster than most other electricity production technologies. For many engines 5-15 minutes are needed. Large gas engines have been successfully developed and tested for start to full electrical load in less than one minute. Engines have been developed for fuel switch during operation. Part load is possible with only slightly decreased electric efficiency. The dual-fuel engines have the least decrease of efficiency at part load. Gas engines have better part load characteristics than gas turbines. To operate a gas engine in power-only mode, the exhaust gas can be emitted directly to the atmosphere without heat extraction (but with de-NOx if required), whereas engine heat (about 50 per cent of total heat) must be removed by a cooler. Approximately 10 per cent of O&M costs can be saved in power-only mode. Most gas engine based CHP plants installations include a short time heat storage. This leads to more flexibility in production planning.

Advantages

Gas engines are known and proven technology making it a highly reliable technology. Gas engines can operate on moderate gas pressures. Gas engines can be supplied by a gas pressure of less than 1 bar(g). The pre-chamber lean-burn technology often requires a pressure for the pre-chambers of approx. 4 bar(g).

Gas engines has one of the lowest expenses per conservation as cold reserve, per cold start, and operation in transient mode. Also, the dependency between their overall efficiency and output level is not so tight, so they have (better) good performance through their power range. That’s why those engines take part in systems where the power load (electricity or heat) varies widely.

Disadvantages

Gas engines cannot be used to produce considerable amounts of high-pressure steam, as approx. 50 per cent of the waste heat is released at lower temperatures. As the engine, generator and other basic equipment comes as compact aggregate, the concentrated weight is an obstruction for large scale engines, due to transportation issues.

Emissions/environment

Spark ignition engines comply with national regulations within EU by using catalyst and/or lean-burn technology to reduce the NOx emission. The content of other air pollutants than NOx in the flue gas from a gas engine is generally low.

Gas-fired reciprocating engines in Bulgaria

These engines are widely used in Bulgaria’s DH sector as well as in industrial installations with specific heat demand requirements. Overall, gas engines cover ≈ 1 per cent of the total electricity production in Bulgaria.

DHCs are operating at least one engine at Bourgas, Varna, Pleven, Vratza, Veliko Tarnovo, Razgrad and Pernik. Annually, they are responsible for ≈ 10 per cent of the gas-fired electricity production in Bulgaria. Compare this to ≈ 30 per cent from Toplofikacia Sofia.

More than 10 greenhouse and industrial installations, as well as few buildings, also use such engines (altogether accounting for ≈ 5 per cent of the gas-fired electricity production in Bulgaria).

Biogas- and syngas-fired reciprocating engines in Bulgaria

Reciprocating engines are also run on gaseous fuels, which are different from gas and can, in some cases, be renewable. Such engines are not widely available in Bulgaria. Currently, only a few are utilising syngas from wastewater treatment facilities – three units at Sofiyska Voda AD with a total capacity of 3 MW – and a few from agricultural waste.

Combined Cycle Gas Turbines

Brief technology description

Main components of combined-cycle gas turbine (CCGT) plants include: a gas turbine, a steam turbine, a gear for the gas turbine (if needed), a generator/s, and a heat recovery steam generator (HRSG)/flue gas heat exchanger, the condenser can be cooled by the DH net return water, sea/lake water or cooling tower. In the case of CHP, the electrical efficiency of CCGT installations suffers from the higher cooling temperature of DH water, but the overall thermal efficiency is higher, than in condensation mode of operation.

The power generated by the gas turbine is typically two to three times the power generated by the steam turbine. An extraction steam turbine shifting from full condensation mode at sea temperature to full back-pressure mode at district heat return temperature will typically lose about 10 per cent of its electricity generation capacity. For example, a 40 MW gas turbine combined with a 20 MW steam turbine (condensation mode), loses 2 MW, (10 per cent of 20 MW) or 3 per cent of the total generating capacity (60 MW).

Typical capacities

Large scale CCGT (100 – 400 MW with extraction steam turbine) and medium scale (10 – 100 MW with back pressure steam turbine). Most CCGT units have an electric power of > 40 MWe.

Regulation ability and other power system services

CCGT units are to some extent able to operate at part load. This will reduce the electrical efficiency and often increase the NOx emission. If the steam turbine is not running, the gas turbine can still be operated by directing the hot flue gasses through a boiler designed for high temperature or into a bypass stack. The larger gas turbines for CCGT installations are usually equipped with variable inlet guide vanes, which will improve the part-load efficiencies within the 85-100 per cent load range, thus making the part-load efficiencies comparable with conventional steam power plants in this load range. Another means to improve part-load efficiencies is to split the total generation capacity into several CCGTs. However, this will generally lead to a lower full load efficiency compared to one larger unit. The NOx emission is generally increased during part load operation.

Advantages

Large gas-turbine-based combined cycle units are world leading solutions in electricity production efficiency when it comes to fuel-based power production technologies. Smaller CCGT units have lower electrical efficiencies compared to larger units. Units below 20 MWe are few and will face close competition with single-cycle gas turbines and reciprocating engines. Gas-fired CCGTs are characterised by low capital costs, high electricity efficiencies, short construction times and short start-up times.

Disadvantages

The economies of scale are substantial, i.e. the specific cost of plants below 200 MWe increases as capacity decreases. The high air/fuel ratio for gas turbines leads to lower overall efficiency for a given flue gas cooling temperature compared to steam cycles and cogeneration based on internal combustion engines.

Emissions/environment

Gas turbines have continuous combustion with non-cooled walls in the combustion chamber. This means a very complete combustion and low levels of emissions (except for NOx). Developments focusing on the combustor(s) have led to low NOx levels. Flue gas post-treatment can consist of SCR catalyst systems etc.

Gas-fired CCGT installations in Bulgaria

There are two CCGT installations, both are operating in CHP mode (heat and power production). The first of them is a part of the DH system in the city of Pleven, and it is the result of a reconstruction of an ordinary Rankin cycle extraction steam turbine unit to a CCGT by adding a General Electric LM-2500 G4 gas turbine and transformation of an old steam generator to a HRSG. The second one is built by Siemens as a new CCGT plant on the site of the Nord DH plant in the city of Plovdiv, gas turbine is Siemens SGT-700. Both installations have overall efficiency at nominal load over 94 per cent, but in summer operate in efficiency deterioration, when the DH load is too low (sometimes under the installations' technical minimums) and additional cooling (emergency cooling) is needed to be kept in operation.